

ATTACHMENT E



**TRANSMISSION COST/BENEFIT
STUDY REPORT PREPARED FOR
THE COUNCIL OF THE CITY OF
NEW ORLEANS
[Redacted Version]**

**IN COMPLIANCE WITH COUNCIL
RESOLUTION No. R-04-66**

ENTERGY SERVICES, INC.

September 21, 2004

Table of Contents

Executive Summary	1
I. Cost/Benefit Study Background.....	6
A. Entergy System Overview.....	6
B. Merchant Generation Development	7
C. LPSC Phase II Transmission Study	8
II. Cost/Benefit Transmission Study for CNO.....	9
A. Scope	9
III. Study Process	9
A. Transmission System Modeling.....	9
B. PROMOD IV HMC Analysis	10
1. Overview of PROMOD IV HMC program.....	10
2. PROMOD IV HMC Study Model.....	11
3. PROMOD IV HMC Initial Case Run	12
C. Examined Transmission Projects	13
1. Down Stream of Gypsy (DSG) Projects	13
2. Amite South import improvement plan.....	15
D. PROMOD IV HMC Change Case Runs	16
IV. Cost/Benefit Analysis.....	16
A. Determination of Annual Revenue Requirement	16
B. Determination of the Net Impact of the Transmission Project Analyses	17
V. Study Results.....	18
VI. Discussion of Results	20
A. Study Summary	20
B. Limitations inherent in the Cost/Benefit study	21
C. Implementation of the Cost/Benefit Study Results	21

List of Appendices

- Appendix A: Entergy Transmission Map
- Appendix B: Executive summary of LPSC Phase II Transmission Study
- Appendix C: List of optional projects committed by merchant generators
- Appendix D: PROMOD IV HMC Input details (Redacted)
- Appendix E: PROMOD IV HMC Transmission Results (Redacted)
- Appendix F: Transmission map indicating location of examined transmission projects
- Appendix G: Detailed analyses showing the determination of the net impact over the study period (Redacted)

Executive Summary

This study, referred to as the CNO Transmission Study, examined Entergy System ("System") transmission expansion alternatives aimed at improving reliability and at alleviating internal limitations associated with the System's control area, with a focus on the Amite South region of Entergy in general, and the area within Amite South referred to as Down Stream of Gypsy in particular. Entergy Services, Inc. ("ESI" or the "Company") on behalf of Entergy New Orleans, Inc. ("ENO") undertook this study at the request of the Council of the City of New Orleans ("CNO" or the "Council"). More specifically, Council Resolution No. R-04-66 provided:

ENO will provide the Council and its Advisors by May 1, 2004, or on such other date as may be mutually agreed upon by the Council's Advisors and ENO, with a study which details its short-term and long-term transmission planning objectives and processes based on both economic and reliability needs for service to its native retail load. The study should detail the cost and timing of transmission improvements which increase the availability of lower-cost sources of power to ENO ratepayers. A cost-benefit analysis should be performed to determine the economic benefit of proposed transmission upgrades, comparable to the phase I, phase II study initially required by the LPSC in settlement of Delaney. ENO should consult with the Advisors to the Council on the scope and method of the analysis within 30 days of the adoption of this Resolution and Order.

The PROMOD IV Hourly Monte Carlo ("HMC") model program was used to perform the detailed combination of transmission and production costing analyses. The study process itself involved numerous computer generated or production cost simulations based on the PROMOD IV HMC model. The study contained the most current information available and was based on transmission projects determined to be beneficial in improving reliability and alleviating limitations within Amite South. Each study required roughly five hours of set-up time, approximately twenty to thirty hours of computer run time, and about ten hours for post processing activities.

The study was conducted in two phases. The first phase focused on the cost/benefit evaluation of reliability improvements in the area known as Down Stream of Gypsy ("DSG") (the geographic area within the Amite South area that is south of the Little Gypsy generating plant owned by Entergy Louisiana, Inc.). It should be noted that, while projects aimed at improving reliability can provide economic benefits, their selection is not dependent on that expectation. The following projects were identified as being candidates for implementation:

DSG PROJECT DESCRIPTION
Upgrade 230kV line segments: Gypsy-South Norco-Prospect-Good Hope
Good Hope Substation Upgrades: 1 breaker, 4 switches
Norco South Substation Upgrades: 1 breaker, 4 switches
Prospect Substation Upgrades: 4 breakers, 16 switches
Convert Waterford-Luling-Waggaman-Ninemile from 115 kV to 230 kV
Waterford Substation: Install 3 breakers for Gypsy-Luling line cut-in
Luling Substation: Install 300 MVA autotransformer, 3 breakers
Waggaman Substation Upgrades: 3 disconnect switches, 1 circuit switcher
Ninemile Substation Upgrades: Install 3 breakers, expand control house
27 miles of line conversion from Waterford-Luling-Waggaman-Ninemile
Upgrade portions of Waterford-Ninemile 230kV line
Install a parallel 500MVA, 230/115kV autotransformer at Gypsy
Upgrade Luling-American Cyanamid line
Install 300MVAr SVC at Ninemile
Install 410 MVAR of Capacitor Banks: - Group 1: Behrman 230, Napoleon 230, Destrehan 230 kV (216 MVAR) - Group 2: Snakefarm 230 (64.8 MVAR), Paterson 115 kV (43.2 MVAR) - Group 3: Waggaman 230 (64.8 MVA), Poydras 115 (21.6 MVA)
Install two 84 MVAr capacitor banks at Michoud 230kV
Install one 146 MVAr capacitor bank Ninemile 230kV

The estimated cost to complete these projects is approximately \$88 million. Certain projects were completed June 1, 2004, and the remainder is scheduled for completion over the next three years. Production cost simulations were done excluding these projects (the "Without DSG Case") and including these projects (the "With DSG Case").

Two PROMOD IV HMC analyses were made for the With DSG Case. The first analysis ("Upper Bound") assumes that the reliability parameters obtained with these upgrades were maintained throughout the study period. The second analysis ("Lower Bound") assumes that these reliability parameters would decline over time as a function of load growth and the uncertainty as to additional generating capability in the region in the later years. These two analyses permitted the Company to estimate the upper and lower bounds of the impact of the transmission projects on fuel and purchased power costs.

Overall the study shows positive results, with the implementation of all projects yielding an overall net benefit ranging from \$134 to \$266 million to Entergy's customers over the 2005-2026 study period. The transmission projects identified in this study would cost approximately \$88 million and would need to be completed by 2007 in order to obtain the estimated benefits discussed above.

The transmission revenue requirement analysis, summarized in the following table, shows the net present value from 2005 through 2026 of the DSG projects evaluated in this study. The net present value calculation uses an 8.5% discount rate, which is based on an approximation of the net of tax overall rate of return. The study assumed EGSI-Texas enters deregulation by July 1, 2005. A net decrease in costs is shown in parentheses, while increases are shown as positive numbers.

LOWER BOUNDS
Net Impact (\$000's)

<u>Item</u>	<u>EAI</u>	<u>ELI</u>	<u>EMI</u>	<u>ENO</u>	<u>EGS-LA</u>	<u>EGS-TX</u>	<u>Entergy</u>
Increase in Fixed Costs	\$18,966	\$47,722	\$12,726	\$6,200	\$15,629	\$14,211	\$115,453
Change in Fuel and Purchased Power Costs	\$7,442	(\$157,346)	(\$31,675)	(\$51,732)	(\$28,379)	\$12,369	(\$249,322)
Net Impact	\$26,407	(\$109,624)	(\$18,949)	(\$45,532)	(\$12,750)	\$26,579	(\$133,868)

UPPER BOUNDS
Net Impact (\$000's)

<u>Item</u>	<u>EAI</u>	<u>ELI</u>	<u>EMI</u>	<u>ENO</u>	<u>EGS-LA</u>	<u>EGS-TX</u>	<u>Entergy</u>
Increase in Fixed Costs	\$18,966	\$47,722	\$12,726	\$6,200	\$15,629	\$14,211	\$115,453
Change in Fuel and Purchased Power Costs	\$9,582	(\$233,640)	(\$54,362)	(\$88,709)	(\$33,320)	\$19,388	(\$381,062)
Net Impact	\$28,548	(\$185,918)	(\$41,636)	(\$82,510)	(\$17,692)	\$33,599	(\$265,608)

The second phase of this study focused on transmission projects that would alleviate internal and external interface limitations in the Amite South region. The following were identified as projects that could have a beneficial effect on the constraints in the Amite South region:

AMITE SOUTH PROJECT DESCRIPTION
Rebuild 230 kV Line from Coly to Vignes
Rebuild 230 kV Line from Conway to Bagatelle
Build New 230 kV Line from Panama to Dutch Bayou and reconfiguration around Dutch Bayou substation

The cost of these projects is estimated at approximately \$43 million. Again, two cases

were developed. The base case excluded the previously discussed reliability improvements in DSG region, as well as the above-listed three projects. The change case included both the DSG projects as well as the three Amite South projects.

Two PROMOD IV HMC change case analyses were made. The first analysis ("Upper Bound") assumes that enhanced transfer limits produced by the projects were maintained throughout the study period. The second analysis ("Lower Bound") assumes that the enhanced transfer limits would decline over time as a function of load growth and the uncertainty as to additional generating capability in the region in the later years. These two analyses permitted the Company to estimate the upper and lower bounds of the effect of the transmission projects on fuel and purchased power costs. It should be noted that the changes in fuel and purchased power costs reflect the combined effect of the DSG and the Amite South projects.

Overall the study shows positive results, with the implementation of the DSG and the three Amite South projects yielding an overall net benefit ranging from \$175 to \$386 million to Entergy's customers over the 2005-2026 study period. The three Amite South transmission projects identified in this study would cost approximately \$43 million and would need to be completed by 2006 in order to obtain the estimated benefits discussed above.

The transmission revenue requirement analysis, summarized in the following table, shows the net present value from 2005 through 2026 of all the projects evaluated in this study. The net present value calculation uses an 8.5% discount rate, which is based on an approximation of the net of tax overall rate of return. Again, the study assumed EGS-Texas enters deregulation by July 1, 2005. A net decrease in costs is shown in parentheses, while increases are shown as positive numbers.

LOWER BOUNDS
Net Impact (\$000's)

<u>Item</u>	<u>EAI</u>	<u>ELI</u>	<u>EMI</u>	<u>ENO</u>	<u>EGS-LA</u>	<u>EGS-TX</u>	<u>Entergy</u>
Increase in Fixed Costs	\$31,708	\$62,561	\$21,270	\$9,402	\$26,122	\$23,740	\$174,802
Change in Fuel and Purchased Power Costs	(\$55)	(\$209,194)	(\$54,501)	(\$54,190)	(\$47,338)	\$15,924	(\$349,353)
Net Impact	\$31,653	(\$146,633)	(\$33,231)	(\$44,788)	(\$21,215)	\$39,664	(\$174,551)

UPPER BOUNDS
Net Impact (\$000's)

<u>Item</u>	<u>EAI</u>	<u>ELI</u>	<u>EMI</u>	<u>ENO</u>	<u>EGS-LA</u>	<u>EGS-TX</u>	<u>Entergy</u>
Increase in Fixed Costs	\$31,708	\$62,561	\$21,270	\$9,402	\$26,122	\$23,740	\$174,802
Change in Fuel and Purchased Power Costs	(\$4,210)	(\$312,650)	(\$101,897)	(\$93,785)	(\$64,800)	\$16,819	(\$560,523)
Net Impact	\$27,498	(\$250,089)	(\$80,267)	(\$84,384)	(\$38,678)	\$40,559	(\$385,721)

These studies measured the long-term implications of the transmission project alternatives using the PROMOD IV HMC production cost model, configured with a detailed representation of the Entergy Transmission System. These analyses modeled both merchant generation that was already in commercial operation and merchant generation that was expected to be in commercial operation by the summer of 2005. The studies also considered all transmission improvements committed to by the merchant generators or by the System to meet its native load requirements. The impact on fuel and purchased power costs were calculated through December 2013 using the PROMOD IV HMC model and were interpolated for the remaining years, through 2026.

These results could be impacted by any changes to the following, but not limited to the following input assumptions:

- The amount of merchant capacity that is available to serve the System's load.
- The fuel prices (gas, oil, coal, and nuclear) and unit characteristics (heat rates, forced outage rates, etc.) for Entergy's existing capacity.
- The External Market Prices ("EMP") of the adjacent power markets of Southern Company, the Midwest, and TVA.
- The cost of the transmission projects and the proposed schedule for completing the transmission expansion alternatives.

Each of these factors affecting the transmission analysis can and does change on a continual basis, making transmission planning a dynamic process. For instance, the recent influx of merchant generation is a significant factor in calculating the forecasted savings associated with these projects. Changes in the availability of generating resources, load forecast, and unit commitment could impact the decisions as to any particular project. Also, while the net savings appear substantial, they would be realized only over a 22 year period, and equate to only a very small percentage of total production costs. The results of these analyses show savings in bus bar production costs ranging from a quarter of one percent to one percent. While the Company has made a

conscientious effort to accurately estimate the impact of these transmission projects on fuel and purchased power costs, estimates of fuel and purchased power costs over a twenty-two year period cannot be deemed to be accurate within plus or minus one percent.

I. Cost/Benefit Study Background

The Council of the City of New Orleans (“CNO” or the “Council”) issued Resolution No. R-04-66 re: Transmission reporting requirement and requested Entergy New Orleans (“ENO”) to perform a cost/benefit study to improve Amite-South transmission limitations and any other transmission limitation that limit ENO’s ability to utilize more economic generation resources to meet ENO’s and ELI’s retail load demand subject to the Council’s jurisdiction. After having met with the Council Advisors, ENO committed to perform a cost/benefit study to determine the economic benefits of proposed transmission upgrades in the DSG and Amite South areas comparable to the phase I, phase II study initially required by the LPSC in settlement of Delaney.

A. Entergy System Overview

The Entergy Transmission System (sometimes referred to as the “System”) is an interconnected network of electric transmission facilities consisting of approximately 16,000 miles of lines spanning 112,000 square miles of service area in four states. The Entergy Transmission System has seventy-four external tie lines with fourteen adjacent utility systems, in voltages ranging from 69 kV to 500 kV. The combined thermal capacity of the seventy-four external tie lines amounts to approximately 30,000 megawatts (“MW”). However, the maximum simultaneous import capability into the Entergy Transmission System is only about 3,900 MW, which occurs in the summer season and the simultaneous export capability of the System is approximately 2,600 MW, which also occurs in the summer season.

The disparity between the total capacity of the external ties and the transfer capability across the external interfaces results from the nature of physical flows on an electrical network, including the resultant flows in the event of a component outage. The System must be able to withstand the loss of the most critical transmission line without the resulting flows overloading any of the remaining transmission lines. The same situation applies to the electrical network internal to the System. Transfer capability is dependent upon both System topology and industry rules that govern System operations.

Much of the Entergy Transmission System as it exists today evolved from five individual systems, which were constructed by the five separate Operating Companies that now make up the Entergy System. Many of the existing transmission corridors were acquired 50 to 100 years ago and were developed in

order to enable local load to be served by local generation within each of the Operating Companies' service areas. The lack of transmission interconnections between Operating Companies, as well as between Entergy and its neighbors, resulted in what is seen today as limitations to the movement of power between some geographical areas of the Entergy Transmission System and between the Entergy Transmission System and its neighbors. The System has been upgraded over the last 100 years, but until the addition of the 500 kV extra high voltage system ("EHV") the basic topology of the System did not deviate much from the lines as they were originally laid out. Local geography and jurisdictional boundaries, in combination with load and generation placement, defined the topology of the transmission grid, which defined transfer capabilities.

The addition of the 500 kV back-bone to the System in the 1960s enhanced transfer capabilities across the jurisdictional and geographical boundaries, which is why the System has the magnitude of transfer capabilities that exist today

For reference, a map of the Entergy Transmission System is provided in Appendix A.

B. Merchant Generation Development

Since 1998, over 180 requests have been made by merchant generation developers to study the interconnection of their facilities, totaling over 100,000 MW of generation capacity, to Entergy's Transmission System. Over half of those requests were for locations within the state of Louisiana. However there is only one merchant facility located within Amite South and none in the DSG area. A significant portion of those requests was carried through to the construction phase. To date, merchant generation developers have completed construction of about 16,000 MW of generation within the Entergy Transmission System foot print, with approximately an additional 3,000 MW still under construction.

The facilities that have been interconnected present a challenge to the existing System, which was constructed over time to accommodate Entergy System's generation mix and native load requirements. The increased demand by the merchant generators to utilize the transmission grid has resulted in power flows across the transmission network that was never contemplated. These additional power flows have revealed transmission bottlenecks that limit the movement of power across the Transmission System.

Recognizing that merchant generation would have a significant impact on the operation of the System, the cost/benefit analysis includes all merchant generation that was in commercial operation or that was expected to be in commercial operation by the summer of 2005.

C. LPSC Phase II Transmission Study

In LPSC Order No. U-23356-A, dated April 12, 2002, the Louisiana Public Service Commission directed the Company to perform a cost-benefit analysis (hereinafter referred to as the "Phase II Study") based on the transmission screening study results previously presented in LPSC Docket No. U-23356 (hereinafter referred to as the "Phase I Study").

Approximately 19,000 MW of merchant generation was considered in the service area at the time of the Phase II study. However, only approximately 13,900 MW of generation was modeled along with all of the optional transmission projects that had been identified for each of the plants.

The objective of the Phase II study was to further evaluate the benefits to jurisdictional customers of transmission expansion plans aimed at alleviating internal and external interface limitations associated with Entergy's control area. This evaluation initially examined transmission flow patterns based on an economic dispatch of generation in the Entergy control area; evaluations then were performed to examine the proposed projects that would be necessary to improve that flow of energy. Transmission alternatives were evaluated using a cost-benefit analysis.

Because the study was not intended to address the impact of external system flows on the Entergy Transmission System, which would not be feasible, it did not focus on identifying transmission projects to enhance export capability. The study also did not evaluate the effects of the implementation of an RTO and real-time congestion management structure.

Three set of projects were examined through Phase II study. Set A included transmission projects identified to improve the Amite-South interface, Set B included the Set A projects and an additional transformer at McAdams to increase the import into Entergy. Lastly, projects were added to Set B to form Set C projects to relieve some local constraints across the system. All three sets of projects indicated net benefits to the Entergy System. The executive summary of the LPSC Phase II study is contained in Appendix B.

II. Cost/Benefit Transmission Study for CNO

A. Scope

The objective of the cost/benefit study for CNO is to evaluate the benefits to customers and especially to the jurisdictional customers of ENOI and ELI of implementing certain transmission projects in the DSG and Amite South area.

Three cases were analyzed for this study in PROMOD IV HMC program.

Without DSG Case (DSGREM)

This case was performed to analyze the production cost to serve the entire load in Entergy system with no project additions in DSG and Amite South.

With DSG Case (CNOREF)

This case was performed to analyze the production cost with the addition of the DSG projects.

Study Change Case (ADDSETA)

This case was performed to analyze the production cost with both DSG and Amite South projects. To do so, it considered both the proposed projects in the With DSG case and in Amite South (Set A Projects per LPSC Phase II study).

A cost/benefit analysis was done by comparing the Without DSG case to the With DSG case and to the Study Change case.

Because the study was intended to address the cost/benefit for the ENOI and ELI customers, it did not focus on relieving any other constraints on the rest of the system. Also, the study did not evaluate the effects of the implementation of an RTO and real-time management structure.

III. Study Process

A. Transmission System Modeling

The study was initiated by constructing the Without DSG case transmission model, which represented the interconnected Transmission System over the study period. The Without DSG case served as a reference point against which transmission alternatives could be evaluated. The transmission model is

necessary in the determination of transmission limitations, in the evaluation of projects to reduce those limitations, and in the security constrained economic dispatch performed by the PROMOD IV HMC program. The Without DSG case transmission model was developed by using the topology and load distribution of the summer 2004 PSS/E load flow case.

In developing the Without DSG case transmission model for this analysis, the Company incorporated known projects other than those identified in DSG and Amite South area that had been committed to serve native load by either the Entergy System or by other parties at the time of the study.

The Company also considered in the Without DSG Case those transmission projects for which commitments have been made by the merchant generators consistent with certain Interconnection and Operating Agreements. These projects are listed in Appendix C.

B. PROMOD IV HMC Analysis

1. Overview of PROMOD IV HMC program

PROMOD IV HMC is a production-costing model designed to simulate the operation of the Entergy System by economically dispatching the utility's generating resources subject to various unit operating constraints. This model simulates a market with an integrated hourly chronological DC power flow, simulates unit forced outages, calculates the fuel and purchased power costs to serve the native load, and determines the production cost for each Entergy Operating Company.

The PROMOD IV HMC model was chosen because it provides the following features:

- Utilizes an hourly chronological optimal dispatch of available resources given various operational constraints.
- Monitors hourly transmission flows on designated branches given identified contingencies.
- Estimates fuel and purchased power expenses for each Operating Company as well as for the Entergy System by incorporating the terms and algorithms of the Entergy System Agreement accounting logic.
- Models the Transmission System with individual line and bus representation using the Transmission Analysis Module ("TAM").
- Provides hourly locational marginal pricing.
- Models defined interfaces based on historical system constraints and the program dispatches in a manner that adheres to import and export limits.

The Transmission Analysis Module in PROMOD IV HMC provides a more detailed depiction of the Transmission System than was available in the past, by allowing representation of individual transmission facilities (e.g., lines, transformers, phase shifters, etc.). TAM performs a security constrained economic dispatch using a DC load flow for each hour of the study period. However, one of the major limitations of TAM is the run time. It takes approximately twenty-nine hours of computing time to run a ten year simulation while monitoring approximately one hundred transmission constraints. Monitoring more transmission constraints increases computation time significantly.

Other models such as Midas and Prosym were considered as potential alternatives to the PROMOD IV HMC model. Some of the same features listed above are also contained in these and other production costing models. However, the decision to migrate to the PROMOD IV HMC model was based primarily on the Company's existing expertise with PROMOD, on availability of the Entergy System Agreement logic, on PROMOD's general acceptance by the FERC and each state regulatory commission, and on the detailed transmission modeling available that can be reflected in PROMOD IV HMC.

2. PROMOD IV HMC Study Model

The following inputs were considered in developing the PROMOD IV HMC study model:

- PROMOD Topology
- Sales Forecast
- Load Forecast
- Entergy Fossil Units
- Merchant Generation
- Fuel Prices
 - Gas
 - Oil
 - Coal
 - Nuclear (including nuclear characteristics)
- Economy Price Curve
- SO₂ Emissions
- Transactions
 - Hydro
 - Cogeneration
 - Economy Purchases and Sales
 - Summer Purchases
 - Exchange
 - Co-Owner
- Security Region Data

- Transmission
- Reliability Must-Run requirement
- Simulation Parameters

The detailed descriptions of these inputs are provided in Appendix D.

3. PROMOD IV HMC Initial Case Run

The following set of assumptions was applied in developing the Initial Case run:

- The Company included approximately 13,800 MW of merchant generation in the Entergy System. At the start of this study, approximately 13,341 MW were either on-line or had scheduled test power and were scheduled to be on-line by January 2005. The remaining 489 MW of generation were scheduled to be on line by the summer of 2005. At the time when the analysis was developed for this analysis, 13,831 MW represented an accurate projection of merchant generation in the Entergy footprint.

[Following data has been redacted]

All other PROMOD IV HMC modeling assumptions are described in Appendix D.

C. Examined Transmission Projects

The Transmission Planning Group examined two sets of projects to address reliability and economic issues in the DSG and Amite South area.

The details of these two sets of projects are as follows:

1. Down Stream of Gypsy (DSG) Projects

- Project No. 1 :
Rebuild 230 kV line from Little Gypsy-South Norco-Prospect - Goodhope (ELI)

The Gypsy to Goodhope line is 7 miles long. The present rating of the Gypsy to Goodhope line is 570 MVA and the line was found to be constrained upon the loss of Waterford to Ninemile 230 kV line. Benefits could be achieved only by rebuilding Gypsy-Goodhope line. These lines were modeled to be in service in June 2005. The estimated cost of these lines including overheads is \$9,200,000 including substation work at Goodhope, Norco South and Prospect.

- Project No. 2 :
Upgrade 230 kV line from Waterford to Ninemile (ELI)

The Waterford to Ninemile line is 31 miles long. The present rating of the Waterford to Ninemile line is 639 MVA. This line is built to a higher rating except for the last section between Churchill to Ninemile. Benefits could be achieved only by rebuilding this last section of the line. The upgrade of this section was modeled to be in service in January 2007. The estimated cost of this line including overheads is \$5,600,000.

- Project No. 3 :
Install 230/115 kV autotransformer at Luling and convert Waterford-Luling-Waggaman-Ninemile 115 kV line to 230 kV (ELI)

The current line is from Little Gypsy-Luling-Waggaman-Ninemile bypassing Waterford substation and is 29 miles long. The present rating of the Gypsy -Luling-Waggaman-Ninemile line is 174 MVA and the line was found to be constrained upon the loss of Waterford to Ninemile 230 kV line. Benefits could be achieved only by converting this line to 115 kV and connecting it to Waterford substation. A 230/115 kV, 300 MVA transformer is also required at Luling to tap the voltage down to serve 115 kV path going towards Raceland. This project was modeled to be in service in January 2007. The estimated cost of this project including

overheads is \$34,600,000 including substation work at Luling, Waggaman and Ninemile.

- Project No. 4 :
Rebuild 115 kV line from Luling to American Cyanamid (ELI)

The Luling to American Cyanamid line is 7 miles long. The present rating of the Luling to American Cyanamid line is 159 MVA and the line was found to be constrained upon the loss of Waterford to Ninemile 230 kV line. Benefits could be achieved only by rebuilding Luling to American Cyanamid line. These lines were modeled to be in service in January 2007. The estimated cost of these lines including overheads is \$5,600,000.

- Project No. 5 :
New 230/115 kV autotransformer at Little Gypsy (ELI)

The installation of a new 230/115 kV, 500 MVA autotransformer would address the existing Little Gypsy 230/115 kV autotransformer constraint. This new autotransformer was modeled to be in service by January 2007. The estimated cost of this project including overheads is \$4,800,000.

- Project No. 6 :
Voltage Support in DSG area

Various projects were considered for this study to support the voltage in the DSG area. The details of these projects are as follows:

Project	Cost (Million)	In-Service Date
300 MVAR SVC at Ninemile 230 kV	\$14.4	June 1, 2005
Two 84 MVAR capacitor banks at Michoud 230 kV	\$ 1.9	June 1, 2004
146 MVAR capacitor bank at Ninemile 230 kV	\$ 1.9	June 1, 2004
216 MVAR capacitor banks at Behrman, Napoleans and Destrahan 230 kV	\$ 9.6	June 1, 2005
64.8 MVAR at Snakefarm 230 kV and 43.2 MVAR at Paterson 115 kV		June 1, 2006
64.8 MVA at Waggaman 230 kV and 21.6 MVA at Poydras 115 kV		June 1, 2007

These devices will provide voltage support for the DSG area allowing a reduction in the Must-Run requirement on Entergy's less economic gas-fired units. These projects were not modeled in PROMOD IV since it is a DC solution but the estimated cost including overheads of \$27,800,000 is considered for the cost/benefit analysis.

2. Amite South import improvement plan

- Project Nos. 1 & 2:
Rebuild 230 kV line from Coly to Vignes and Rebuild 230 kV Line from Conway to Bagatelle (Louisiana)

The Coly to Vignes line is eleven miles long and the Conway to Bagatelle line is nine miles long. Both are in southeast Louisiana and rebuilding the lines would address the Coly-Vignes 230 kV transmission line constraint. The Conway to Bagatelle 230 kV line is a tie line between EGSI-Louisiana and ELI-South. The present rating of the Conway to Bagatelle line is 436 MVA and the line was found to be constrained upon the loss of Willow Glen to Waterford 500 kV line and Coly-Vignes 230 kV line. Benefits could be achieved only by rebuilding both the Conway to Bagatelle line and the Coly to Vignes line. These lines were modeled to be in service in July 2006 and July 2005 respectively. The estimated cost of these lines including overhead is \$34,100,000.

- Project No. 3:
Construct new 230 kV line from Panama to Dutch Bayou (Louisiana)

The Panama to Dutch Bayou line is twenty miles long, and is located in southeast Louisiana. This line would alleviate loading on the Panama-Romeville 230 kV line upon the loss of the Willow Glen to Waterford 500 kV line. This line was modeled to be in service in July 2006. The estimated cost of this line including overheads is \$9,100,000.

For the exact location of these projects, please see Appendix F.

D. PROMOD IV HMC Change Case Runs

The Transmission Planning Group identified two sets of transmission projects, with the intent of relieving the most critical bulk power constraints identified in the DSG and Amite South areas, respectively. These projects were incorporated into the PROMOD IV HMC model to evaluate the proposed improvements in the Transmission System, in accordance with their expected in-service dates. PROMOD IV HMC Case analyses were performed, and Hourly Transmission Flow reports and Monitored Line Limits Summary reports were again generated.

IV. Cost/Benefit Analysis

For this analysis, an estimate was made of the total investment necessary to complete the transmission projects. The analysis calculated the annual revenue requirement associated with the investments in each set of the examined transmission projects. This cost was then offset by the change in the production costs produced by the projects. The end result for each group of projects that was examined was the net impact on total cost, *i.e.*, base rate revenue requirement associated with the added investment, net of the change in the fuel and purchased power costs.

A. Determination of Annual Revenue Requirement

The Company has analyzed the potential net impact of specific transmission projects. These consist of new facilities, as well as upgrades to existing facilities. These specific transmission projects were analyzed in two sets, referred to as the DSG projects and the DSG-Amite South projects. The analysis estimates the net impact of the DSG projects, which consisted of six projects, expected to be completed by 2007. The DSG-Amite South projects are the combination of the DSG projects and three additional projects identified in the LPSC Phase II study that could potentially increase the Amite South import capability.

For each project, an estimate has been made of the total investment necessary to complete the project. The annual revenue requirement associated with the

investment in each of the sets was then calculated, and was compared with the change in production costs produced by that set of transmission projects. The end result is a net impact on the total cost – base rate revenue requirement associated with the added investment net of the change in fuel and purchased power costs. These results were calculated for each Operating Company, with EGS-LA and EGS-TX treated separately, and was summed to obtain the impact on total System costs.

The annual revenue requirement was determined for each project for each of the years 2005-2026. This revenue requirement consisted of the following:

- a) Return on Average Net Investment less accumulated deferred income taxes;
- b) Income Taxes;
- c) Depreciation Expense;
- d) Operation and Maintenance Expense; and,
- e) Other Taxes.

B. Determination of the Net Impact of the Transmission Project Analyses

The net impact of the transmission project analyses has been determined by combining the results of the revenue requirement analyses with the results of the PROMOD IV analyses. The PROMOD IV analyses were conducted for each of the years 2005-2013. The PROMOD IV results from the three cases were compared to determine the impact or change in fuel and purchased power costs for each set of transmission projects that was analyzed. The changes in fuel and purchased power costs that resulted from the PROMOD IV analyses for the years 2008-2013 were averaged, and the six-year average change was used for each of the years 2014-2026. The use of the average value over the 2014-2026 period as the predictor of future values is reasonable.

Two estimates were made of the change in fuel and purchased power costs associated with each set of transmission projects that was studied. The transmission projects increase the transfer capability of energy into the DSG and Amite South area as well as reduce the Must-Run requirement on certain gas-fired units. However, because the transfer capabilities can vary with time, the fuel and purchased power costs can also vary. Two analyses were performed to determine the range within which the costs could possibly fluctuate. The first analysis (“Upper Bound”) assumes that the reliability parameters obtained with these upgrades were maintained throughout the study period. However, over time, as load increases, the transfer capability will decrease unless additional transmission investments are made to maintain that enhanced transfer capability. Also, the uncertainty of the system and the projected load growth in the later years may require committing more must-run units for certain months. Thus, the second

analysis ("Lower Bound") assumes that these reliability enhancements would decline over time as a function of load growth and the uncertainty as to additional generating capability in the region in the later years. The Upper Bound analysis does not include any additional dollars associated with the investment that would be needed to maintain these enhanced limits or improved must-run requirements, as it is not possible at this time to know what investments would be required to achieve that result.

These two analyses permitted the Company to estimate the upper and lower bounds of the impact of the transmission projects on fuel and purchased power costs. Although this Upper Bound analysis produces results that are likely overstated, it establishes a reasonable estimate of the maximum effect that the transmission projects may have on fuel and purchased power costs. The Lower Bound analysis assumes that the enhanced limits decline as a function of load growth as well as uncertainty as to additional generating capability in the region and the more stringent must-run requirements as time goes on. This analysis establishes a reasonable estimate of the minimum effect that the transmission projects may have on fuel and purchased power costs.

Maintaining the enhanced limits and relief on must-run requirement sets the maximum value and reflecting the declining limits with more stringent must-run requirement sets the minimum value. Thus, the reasonably expected net effect of these projects is set forth as a range.

V. Study Results

The tables below reflect the Net Present Value of the estimated changes in costs to Entergy customers as a result of the examined transmission projects. The numbers in the tables indicate that the projects that are the subject of this study may be expected to produce net benefits in the range of \$134 million to \$386 million over the twenty-two year study period.

DSG Projects: Lower Bounds

Net Present Value (\$000's)							
Item	EAI	ELI	EMI	ENOI	EGSI-LA	EGSI-TX	Entergy
Change in Revenue Requirement	\$18,966	\$47,722	\$12,726	\$6,200	\$15,629	\$14,211	\$115,453
Change in Fuel and Purchased Power Costs	\$7,442	(\$157,346)	(\$31,675)	(\$51,732)	(\$28,379)	\$12,369	(\$249,322)
Net Impact	\$26,407	(\$109,624)	(\$18,949)	(\$45,532)	(\$12,750)	\$26,579	(\$133,868)

DSG Projects: Upper Bounds

Net Present Value (\$000's)							
Item	EAI	ELI	EMI	ENOI	EGSI-LA	EGSI-TX	Entergy
Change in Revenue Requirement	\$18,966	\$47,722	\$12,726	\$6,200	\$15,629	\$14,211	\$115,453
Change in Fuel and Purchased Power Costs	\$9,582	(\$233,640)	(\$54,362)	(\$88,709)	(\$33,320)	\$19,388	(\$381,062)
Net Impact	\$28,548	(\$185,918)	(\$41,636)	(\$82,510)	(\$17,692)	\$33,599	(\$265,608)

DSG & Amite South Projects: Lower Bounds

Net Present Value (\$000's)							
Item	EAI	ELI	EMI	ENOI	EGSI-LA	EGSI-TX	Entergy
Change in Revenue Requirement	\$31,708	\$62,561	\$21,270	\$9,402	\$26,122	\$23,740	\$174,802
Change in Fuel and Purchased Power Costs	(\$55)	(\$209,194)	(\$54,501)	(\$54,190)	(\$47,338)	\$15,924	(\$349,353)
Net Impact	\$31,653	(\$146,633)	(\$33,231)	(\$44,788)	(\$21,215)	\$39,664	(\$174,551)

DSG & Amite South Projects: Upper Bounds

Net Present Value (\$000's)							
Item	EAI	ELI	EMI	ENOI	EGSI-LA	EGSI-TX	Entergy
Change in Revenue Requirement	\$31,708	\$62,561	\$21,270	\$9,402	\$26,122	\$23,740	\$174,802
Change in Fuel and Purchased Power Costs	(\$4,210)	(\$312,650)	(\$101,897)	(\$93,785)	(\$64,800)	\$16,819	(\$560,523)
Net Impact	\$27,498	(\$250,089)	(\$80,627)	(\$84,384)	(\$38,678)	\$40,559	(\$385,721)

The results cited above will be affected by the in-service dates of the examined transmission projects, as well as by other factors noted in this report.

VI. Discussion of Results

A. Study Summary

As shown, the net savings in this study appear substantial being in the range of \$134 to \$386 million. However, it should be noted that they would be realized only over a 22 year period, and equate to only a very small percentage of total production costs. The results of these analyses show savings in System bus bar production costs ranging from a quarter of one percent to one percent. While the Company has made a conscientious effort to accurately estimate the impact of these transmission projects on fuel and purchased power costs, estimates of fuel and purchased power costs over a twenty-two year period cannot be deemed to be accurate within plus or minus one percent.

As noted, these results could be impacted by any changes to the following, but not limited to the following input assumptions:

- The amount of merchant capacity that is available to serve the System's load.
- The fuel prices (gas, oil, coal, and nuclear) and unit characteristics (heat rates, forced outage rates, etc.) for Entergy's existing capacity.
- The External Market Prices ("EMP") of the adjacent power markets of Southern Company, the Midwest, and TVA.
- The cost of the transmission projects and the proposed schedule for completing the transmission expansion alternatives.

Each of these factors affecting the transmission analysis can and does change on a continual basis, making transmission planning a dynamic process. For instance, the recent influx of merchant generation is a significant factor in calculating the forecasted savings associated with these projects. Changes in the availability of generating resources, load forecast, and unit commitment could impact the decisions as to any particular project.

B. Limitations inherent in the Cost/Benefit study

Some limitations do exist in the analysis of the Cost/Benefit Transmission Study. For example, the TAM solution methodology did not allow for examination of voltage or stability excursions, the extended run time of the program prevented all lines in the System from being monitored for overloads, and the external control area loads on the transmission System (outside of Entergy) was represented in static form.

PROMOD IV HMC has a DC solution methodology when calculating energy flows across the System and dispatching generation around System constraints. The DC solution methodology kept the computer run times at a manageable level. Consequently, voltage levels at the generating plants and substations on the System were not input into the model.

As mentioned earlier, over one hundred transmissions lines within the Entergy System were monitored for overloads. These were chosen based on the TAM reports and on prior knowledge and studies of the System. However, the long solution time of the model precluded the monitoring of all lines on the Transmission System for overloads. In addition, generation dispatch on neighboring systems was not adjusted to account for perturbations on the Entergy System, and generation dispatch within the Entergy System was not subject to possible transmission contingencies on neighboring systems.

C. Implementation of the Cost/Benefit Study Results

The cost/benefit study provides the Company a better understanding of the impacts of the projects identified in the DSG and Amite-South region on the ratepayers of the affected Companies. Indeed, the System is in the process of executing projects identified as the DSG projects and is committed to move forward with the projects identified in the DSG-Amite South set, all of which are projected to be completed by the summer of 2007. For DSG projects, projected to be in-service in the 2006-07 timeframe, the Company is also evaluating other alternatives that will yield comparable reliability results. However, while impacts on System voltage and stability were determined by the Transmission Planning Group using more sophisticated modeling techniques outside of the PROMOD IV HMC model; it is unlikely that such positive results would be attained with less than full participation on the part of the merchant units.

APPENDIX A

Entergy Transmission System Map

Click on this URL to view the map (need AutoCAD viewer)

http://oasis.e-terrasolutions.com/documents/EES/Entergy_System_Fiber.dwf

APPENDIX B

Executive Summary of LPSC Phase II Study

LPSC Phase II Study: Executive Summary

This study, referred to as the Phase II Transmission Study, explored Entergy System ("System") transmission expansion alternatives aimed at alleviating internal and external interface limitations associated with the System's control area, with a focus on the Amite South region of Entergy. Entergy Services, Inc. ("ESI" or the "Company") on behalf of Entergy Louisiana, Inc. ("ELI") undertook this study at the request of the Louisiana Public Service Commission ("LPSC" or the "Commission").

The Phase II Study has taken just over two years to complete. Some of this time was required due to the conversion to the PROMOD IV Hourly Monte Carlo ("HMC") model, which program was needed to perform the detailed combination of transmission and production costing analyses. Additionally, the study process itself involved a countless number of computer runs. Countless iterations were prepared to ensure that the study contained the most current information available and that appropriate transmission projects were analyzed. Each study required roughly five hours of set-up time, approximately twenty to thirty hours of computer run time, and about ten hours for post processing activities.

In July 2003, the initial Phase II Transmission Study Report (the "interim report" or "July 2003 Study") was posted. The transmission expansion alternatives that had been identified at that point included ten transmission projects located in all state jurisdictions. Subsequently, the Company updated the inputs of the PROMOD IV HMC model to take into consideration transmission projects approved, budgeted, or completed since the inception of the study, and to reflect other updated information. With these updates incorporated into the base case, it was confirmed that four out of the ten transmission projects identified in the July 2003 Study would be obviated by projects that had been approved and/or committed.

The following transmission projects have been committed to, and therefore these projects have been included in the base case:

Louisiana Projects:	Status
a. Upgrade Toledo-Leesville 138 kV Line	Completed by CLECO
b. Second Addis-Choctaw 230 kV Line	Completed – Optional Upgrade
c. Downstream of Gypsy Projects	Operating Committee approval - \$70 million

Texas Projects:	Status
a. Cypress 500/230 kV Auto	Completed – Optional Upgrade
b. Amelia-Helbig 230 kV Line	Completed - \$3.3 million
c. Western Region Reliability Projects	Board approval - \$79 million

Arkansas Projects:	Status
a. Build 3 rd line from ISES-Newport	Approved – Funded by Transmission Customer
b. Install 345/161 kV Autotransformer at Fort Smith	Approved by Oklahoma Gas & Electric
c. Miscellaneous Upgrades	Completed - \$6.3 million
d. Miscellaneous Upgrades	Approved - \$19.2 million

Mississippi Projects:	Status
a. Upgrade Andrus-Greenville	Approved - \$3 million
b. Upgrade Baxter Wilson-Vicksburg	Completed - \$4.4 million
c. New Line South Jackson-Rankin	Under construction - \$10.2 million
d. Miscellaneous Upgrades	Approved - \$9.4 million

The transmission expansion alternatives that have been analyzed in this study include seven transmission projects located in all state jurisdictions. These projects focus on alleviating flow restrictions associated with the most limiting transmission facilities defined during the study process. The Company analyzed the potential net impact of seven specific transmission projects, each of which would improve transfer capability. These specific transmission projects were analyzed in three sets, denoted as Sets A, B, and C. Set A estimates the net impact of three projects designed to improve the Amite South import capability. Set B adds the McAdams transformer to the projects analyzed in Set A. Set C includes all seven projects. A detailed description of the project combinations analyzed is contained in Table 3 to this Report.

Two PROMOD IV HMC analyses were made for each Set of transmission projects. The first analysis assumes that enhanced transfer limits produced by the projects were maintained throughout the study period. The second analysis assumes that the enhanced transfer limits would decline over time as a function of load growth. As explained in section IV.B, below, these two analyses permitted the Company to estimate the maximum and minimum limits of the effect of the transmission projects on fuel and purchased power costs.

Overall, the study shows positive results, with the implementation of all seven projects yielding an overall net benefit ranging from \$128 to \$311 million to Entergy's customers over the 2004-2026 study period. The seven transmission projects identified in this study would cost approximately \$78 million and would need to be completed by 2006 in order to produce the estimated benefits discussed above.

The transmission revenue requirement analysis, summarized in the following table, shows the net present value from 2004 through 2026 for each set of projects evaluated in this study. The net present value calculation uses an 8.5% discount rate, which is based on an approximation of the net of tax overall rate of return. The study assumed EGS-Texas enters deregulation by

January 1, 2005. A net increase in costs is shown in parentheses, while net benefits are shown as positive numbers.

Lower Bounds Net Impact (\$000's)							
Cases	EAI	ELI	EMI	ENOI	EGSI-LA	EGSI-TX	Entergy
Set A	\$6,988	\$106,912	\$16,154	(\$3,839)	\$20,397	(\$19,025)	\$127,587
Set B	\$4,430	\$111,272	\$23,583	(\$3,957)	\$26,123	(\$14,239)	\$147,212
Set C	(\$19,389)	\$134,199	\$34,854	(\$3,462)	\$38,350	(\$13,988)	\$170,564

Upper Bounds Net Impact (\$000's)							
Cases	EAI	ELI	EMI	ENOI	EGSI-LA	EGSI-TX	Entergy
Set A	\$22,017	\$175,192	\$32,267	\$9,697	\$40,602	(\$19,314)	\$260,462
Set B	\$19,047	\$184,164	\$40,856	\$9,845	\$48,311	(\$11,935)	\$290,286
Set C	(\$3,206)	\$205,628	\$55,829	\$9,508	\$56,887	(\$13,720)	\$310,925

This study measured the long-term benefits of the possible transmission expansion alternatives using the PROMOD IV Hourly Monte Carlo ("HMC") production cost model, configured with a detailed representation of the Entergy Transmission System. This analysis modeled both merchant generation that was already in commercial operation and merchant generation that was expected to be in commercial operation by the summer of 2004. The study also considered all transmission improvements committed to by the merchant generators or by the System to meet its native load requirements. Benefits and costs were calculated for 10 years (from January 2003 through December 2012) using the PROMOD IV HMC model and were interpolated for the remaining years, through 2026.

The results of this study are based on the list of assumptions that are attached as Appendix D. These results could be impacted by any changes to, among others, the following input assumptions:

- The amount of merchant capacity that is available to serve the System's load.
- The fuel prices (gas, oil, coal, and nuclear) and unit characteristics (heat rates, forced outage rates, etc.) for Entergy's existing capacity.
- The External Market Prices ("EMP") of the adjacent power markets of Southern Company, the Midwest, and TVA.
- The cost of the transmission projects and the proposed schedule for completing the transmission expansion alternatives.

Each of these factors affecting the transmission analysis can and does change on a continual basis, making transmission planning a dynamic process. Changes in the output of available generating resources will impact the decision as to which projects are pursued in the future.

Also, while the net savings appear substantial, they would be realized only over a 22 year period, and equate to only a very small percentage of total production costs. The Company will incorporate the results of this study into the transmission planning process. This will allow the impact of the projects on the reliability of the System to be more fully analyzed and understood, and will facilitate further consideration of their implementation based on current data and forecasts.

APPENDIX C

List of optional upgrades committed by merchant generators

Appendix C
Committed Optional Transmission Upgrades

Project ID	Merchant Generation Project	Committed System Upgrades
4	Pine Bluff Energy LLC	New 115 kV line from Pine Bluff East Substation to Pine Bluff IP Switching station
		New 115 kV line from Pine Bluff South to Pine Bluff IP Switching Station
		New 115 kV from Pine Bluff IP Switching Station to Pine Bluff IP
9	SRW Cogeneration LP	Bundle 1.46 miles of 138kV Line 549, Dupont #3 to Cow Bulk
		Bundle 1.0 mile of 138kV Line 548, Dupont #3 to Cow Bulk
		Upgrade/replace equipment at Cow Bulk 138/69 kV Substation (includes a 200 MVA transformer, breakers, busses)
		Upgrade Sabine 230kV and 138 kV substations (add 230/138 kV, 300 MVA autotransformer)
		Upgrade 138kV Line 492 (Cow to Sabine)
12	Wrightsville Power Facility, LLC	Wrightsville 115 kV switchyard and 500/115 kV autotransformer
		Upgrade 115kV Mabelvale to White Bluff line (Formerly L.R. Arch St.)
		Upgrade 115kV White Bluff to Mabelvale Line (Formerly L.R. South Line)
		Upgrade 115kV White Bluff to Wrightsville Line (Formerly Lynch Line)
		Upgrade 115kV Little Rock South to Wrightsville Line (Formerly White Bluff Line)
		Upgrade 115kV Lynch to Wrightsville Line (Formerly White Bluff Line)
		Upgrade 115kV Wrightsville-145th Street
		Upgrade 115kV Wrightsville-Lorance Creek Switching Station
		Upgrade 115kV Little Rock Fourche - Little Rock East
		Hot Springs EHV-Replace West Bus Transfer Breaker B1560
		Upgrade 115kV Arch Street - Lorance Creek Switching Station
13	Occidental (Taft)	Upgrade 230 kV line from Frisco to Waterford
		Upgrade 230 kV line from Waterford to Union Carbide
		Upgrade 230 kV line from Union Carbide to Hooker
		Upgrade 230 kV line from Hooker to Waterford
16	Duke Energy Hinds, LLC	Build Rex Brown-Miami-Monument Street 115 kV transmission line
		Upgrade Rex Brown Substation
		Upgrade terminal equipment at Miami Substation
		Upgrade terminal equipment at Monument Street Substation
		Upgrade terminal equipment at South Jackson Substation
		Upgrade South Jackson to Rankin Industrial 115 kV transmission line.
		Upgrade Rankin to Pelahatchie 115 kV transmission line
25	Duke Energy Attala, LLC	Upgrade terminal equipment at Bowling Green Substation
		Upgrade terminal equipment at Kosciusko Substation
		Upgrade terminal equipment at Acona Substation
		Upgrade Attala to Kosciusko transmission line
		Upgrade Acona-Bowling Green transmission line
29	Ouachita Power, LLC	Sterlington 115 kV - Marion 115 kV
		Sterlington 115 kV - Meridian 115 kV
		Sterlington 115 kV - Crossett North 115 kV
		Crossett South 115 kV - Meridian 115 kV
		Huttig 115 kV - Marion 115 kV
		Vicksburg 115 kV - Waterway 115 kV
		Huttig 115 kV - Strong 115 kV
		Crossett North 115 kV - Crossett South 115 kV
		Strong 115 kV - Texas East Station "F" 115 kV
		Tex East Station "F" 115 kV - El Dorado East 115 kV
32	The Dow Chemical Company	Construct a second 230 kV transmission line connecting the Company's proposed Choctaw 230 kV Substation to the Addis 230 kV Substation.
		Equipment/Relay upgrades at Addis to accommodate new line.
51	Acadia Power Partners, LLC	Upgrade (Re-sag) Richard-Jennings 138 kV line
55	Warren Power, LLC	Upgrade 115 kV line from N Vicksburg to West Vicksburg
		Upgrade 115 kV line from West Vicksburg to North Vicksburg
		Upgrade 115 kV line from SE Vicksburg to Bovina
		Upgrade 115 kV line from Clinton to Ray Braswell
65	Union Power Partners, L.P.	Upgrade 115 kV line from El Dorado East to El Dorado
		Upgrade 115 kV line from Texas East Terminal to El Dorado EHV
		Upgrade 115 kV line from Donan Substation to Texas East
		Upgrade terminal equipment at Donan Substation
66	Duke Energy Hot Springs, LLC	Upgrade Arklaoma to Carpenter Dam 115 kV
		Upgrade Butterfield to Hot Springs 115 kV
		Upgrade Butterfield to Haskell 115 kV

Appendix C
Committed Optional Transmission Upgrades

Project ID	Merchant Generation Project	Committed System Upgrades
		Upgrade terminal equipment at Carpenter Dam Substation
		Upgrade terminal equipment at Hot Springs 115 kV Substation
		Upgrade terminal equipment at McNeil Stephens 115 kV Substation
		Upgrade terminal equipment at Butterfield 115 kV Substation
		Upgrade terminal equipment at Camden South 115 kV Substation
		Upgrade terminal equipment at Haskell 115 kV Substation
78	Cottonwood Energy Company, LP	New Hartburg Autotransformer 800MVA, 500/230 kV
		New Cypress Autotransformer 750 MVA, 500/230 kV
		New Cypress Autotransformer 300 MVA, 230/138 kV
83	Bayou Cove, LLC	Build connecting line to the Jennings to Richard 138 kV line
90	MDEA	Rebuild 115 kV line from Delta to Shelby
		Upgrade terminal equipment at Shelby Substation
		Rebuild 115 kV line from Shelby to Roundaway
		Upgrade terminal equipment at Roundaway Substation
		Upgrade terminal equipment at Ruleville Substation
		Ruleville - Schlater 115 kV (Upgrade Schlater 2" IP Riser)
		Upgrade terminal equipment at Schlater
		Upgrade terminal equipment at Browning Substation
		Upgrade terminal equipment at Morehead Substation

APPENDIX D

PROMOD IV HMC Input details [Redacted]



CNO Cost/Benefit Analysis - Reference Case (CNOREF)

This document contains confidential information available only to the Regulated Utility and members of corporate staff. No portion should be shared with any non-regulated business unit, affiliate or member of the public at large without the express permission of Planning Models and Analysis.

Planning Models and Analysis
July, 2004

TABLE OF CONTENTS

TABLE OF CONTENTS	1
EXECUTIVE SUMMARY	2
INTRODUCTION	3
MODEL INPUTS	4
PROMOD TOPOLOGY	5
SALES FORECAST	6
LOAD FORECAST	7
ENTERGY FOSSIL UNITS	9
MERCHANT GENERATION	10
RETIREMENTS	15
GAS FORECAST	16
OIL FORECAST	17
COAL FORECAST	18
NUCLEAR FORECAST	19
SO2 EMISSIONS	20
ECONOMY PRICE FORECAST	21
TRANSACTIONS	23
SECURITY REGION DATA	26
TRANSMISSION	29
SIMULATION PARAMETERS	31

EXECUTIVE SUMMARY

Included in the CNO Cost/Benefit Analysis Reference Case is the “as filed” Strategic Supply Resource Plan for 2005 – 2012 (“SSRP”) which represent a supply procurement strategy based on the responses to the Request for Proposals issued in the Fall of 2002 (the “Fall 2002 RFP”) and Spring 2003 (the “Spring 2003 RFP”) and the Planning Principles review with the Operating Committee in June 2002. The study period for this case is January 2005 through December 2013. The SSRP portfolio consists of long-term resources, a blend of load following resources, and peaking resources.

Adjustments were made to the original SSRP plan discussed above as referenced in the June 1, 2004 CNO Supply Plan filing.

INTRODUCTION

- PROMOD IV Version 8.4.020 (executable dated April 14, 2004) is a production-costing model designed to simulate the operation of the Entergy system by economically dispatching the utility's generating resources subject to various unit operating constraints. This model simulates a market with an integrated hourly chronological DC power flow, simulates unit forced outages, and calculates the fuel and purchased power costs (production cost) effects on each of Entergy's Operating Companies.

MODEL INPUTS

- PROMOD Topology
- Sales Forecast
- Load Forecast
- Entergy Fossil Units
- Merchant Generation
- Fuel Prices
 - Gas
 - Oil
 - Coal
 - Nuclear (including nuclear characteristics)
- Economy Price Curve
- SO₂ Emissions
- Transactions
 - Hydro
 - Cogeneration
 - Economy Purchases and Sales
 - Summer Purchases
 - Exchange
 - Co-Owner
- Security Region Data
- Transmission
- Simulation Parameters

PROMOD TOPOLOGY

- The Entergy control area consists of 15 areas being modeled, one for each Operating Company (EGSI is split between Louisiana and Texas), 6 co-owners and a merchant company. Also ELI is split between north and south and EGSI-LA is split between WOTAB and non-WOTAB.
- These 6 co-owners are part owners of the Arkansas coal units, Independence and White Bluff. One area is a dummy area for the merchant company.

SALES FORECAST

- PROMOD uses a forecast of hourly loads, in EEL format, by Entergy Operating Company and by Co-Owner. A second set of inputs is the monthly peak and average values for each Operating Company. These values were forecast using a “bottom-up approach”, starting first with the development of a retail sales forecast, by revenue class, a separate wholesale sales and company use forecast, and then aggregating those results to input into HELM, the Hourly Electric Load Model. HELM develops the hourly load forecast used in PROMOD.
- The original Entergy Retail Sales Forecast for the years 2004-2013 was developed by the Planning Models and Analysis group.
- Retail Sales Inputs
 - Historical sales from 1993-2002 were used in the analysis
 - Monthly Cooling Degree Days (CDD) and Heating Degree Days (HDD) were calculated from Average Daily Temperatures (ADT) for each legal entity. Heating degree days are measured for temperatures below 60 degrees Fahrenheit (“°F”) while cooling degree days are measured for temperatures above 70°F. There are no HDDs or CDDs calculated for those temperatures between 60 and 70 degrees.
 - Econometric variables are supplied by Economy.com. Service area specific variables are provided for each legal entity.
 - The cogeneration assumptions are as follows: (THE CUSTOMER NAMES AND DATA HAS BEEN REDACTED FROM THE TABLE BELOW)

Customer	Impacted Load Loss	
	OPCO kW Load	Date
	EGSL	
	EGSL	
	EGSL	
	EGSL	
	EGST	
	ELI	
Total Business Plan		

- Model
 - The forecasts are derived using MetrixND, an ITRON product.
 - The forecast includes Operating Company retail and wholesale load.
- Approval
 - The business unit leaders, along with the commercial and industrial groups at each company, reviewed and approved the sales forecast. Final approval was received from each Operating Company President.

LOAD FORECAST

- The Entergy Load Forecast (FEC041) for the years 2004-2013 was developed by the Forecasting and Analysis group in March 2004.
 - Inputs
 - The retail sales forecast described in the Sales Forecast Section.
 - A revised wholesale forecast provided by Power Contracts. This forecast assumes that EAI's wholesale contracts are not renewed once they expire. Those contracts expire as follows: **(REDACTED)**

<u>Contract</u> <u>Ending</u>	<u>Customer</u>
--	------------------------

- A company use forecast that was based on previous year's FERC Form 1 data and escalated by 0.1%.
- Ten-year typical weather for each jurisdiction based on the years 1993-2002.
- Transmission and distribution losses were supplied by Entergy's Rate Design group.
- Revenue Class load shapes for each Operating Company were based on loads and weather for 2002.
- Model
 - The forecasts were derived using HELM, an EEI product.
 - The forecast provides hourly load for each Operating Company by Revenue Class and co-owner, including a forecast for EGSI-TX and EGS LA.

LOAD FORECAST

- The following table contains the peak load forecast.
 - The peak for ETR is coincident. The peak for each Operating Company is non-coincident. (REDACTED)
-
-

ENTERGY FOSSIL UNITS

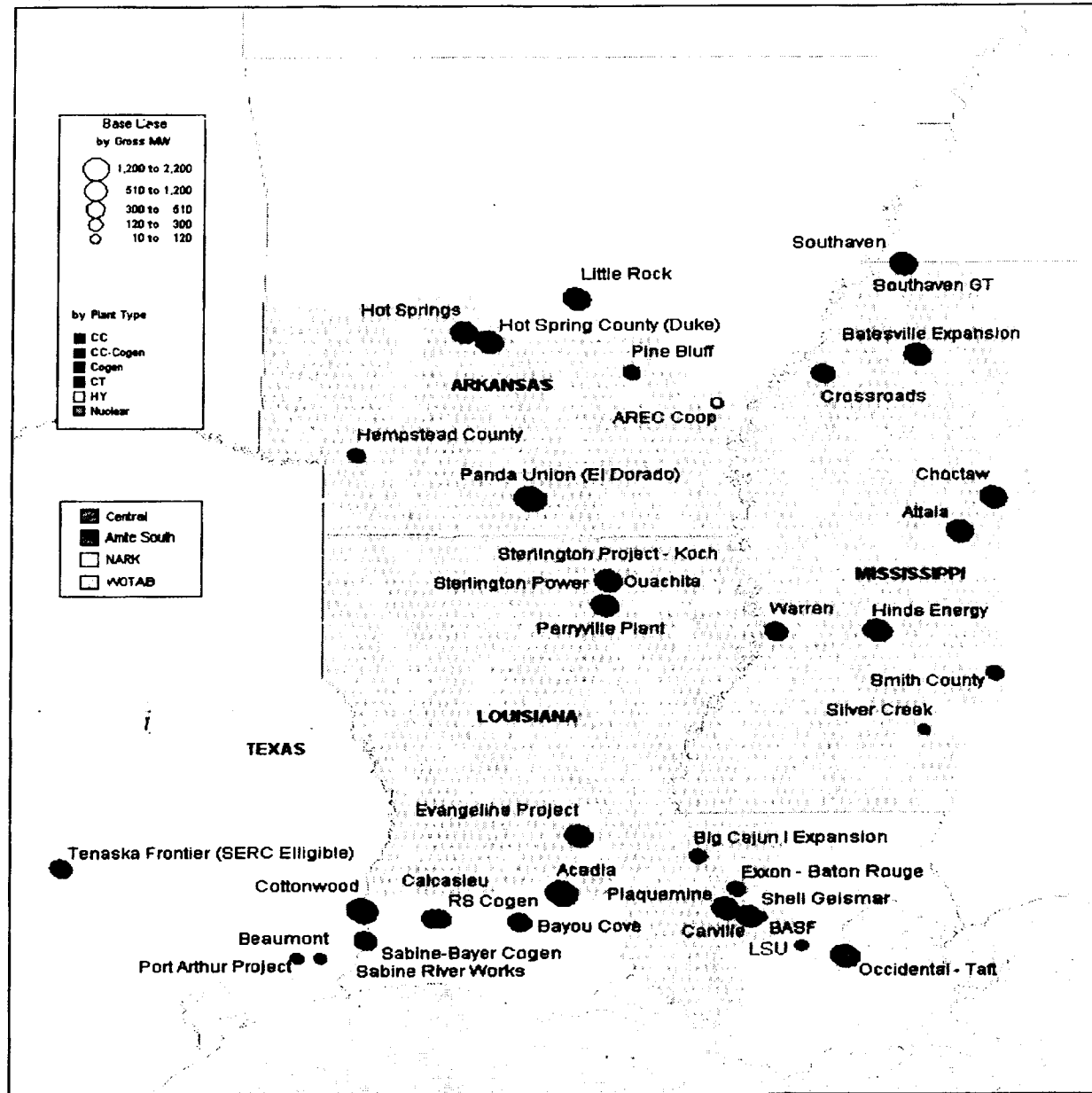
- Unit Capacities
 - Summer and winter capacities were provided by Generation Planning.
 - The summer ratings are those approved by the Operating Committee for the Summer 2003. These ratings were used for each Summer season modeled in the study period.
 - The winter ratings are those approved by the Operating Committee for the Winter 2003/2004. These ratings were used for each Winter season modeled in the study period.
- Maintenance
 - Ten years of scheduled maintenance data were input. Operations Planning collected data from the plants, which included their assumptions for the next 10 years (through Fall 2012). The 2011 maintenance was input for 2013.
 - Planned maintenance information for Cajun 2 Unit 3 was received from Louisiana Generating (“La Gen”) through 2012. Based on the pattern of turbine outages, it was assumed that an outage should occur in 2013.
- Forced Outage Rates
 - Annual forced outage rates and partial availability rates were calculated for each fossil unit from Generation Availability Data Reporting System (“GADRS”) event data for January 2001 through December 2002.
 - All events that were greater than 350 hours in duration were reviewed by Operations Planning to determine if they should be included or excluded from the forced outage rate calculation. Based on that review (to determine if the event was recurring or non-recurring in nature), some events were removed from the calculation.
- Other Fossil Unit Characteristics
 - Mean time to repair (average forced outage hours) – retrieved from GADRS, based on 2001 and 2002 data. In instances where forced outage events were removed from historical data in the forced outage rate calculation, the mean time to repair was recalculated with these hours removed.
 - Ramp rates – Provided by Operations Planning with input from various Plant Managers
 - Heat rate coefficients – Provided by Operations Planning with input from various Plant Managers
 - Dispatch penalty factors – an average of the 2001 and 2002 amounts used in the ISB process.
 - Start-up energy requirements – Provided by Generation Assets in June 2002 with input from various Plant Managers.
 - Accounting heat rates – The most recently available annual average heat rates (2003) for each unit from ISB were used for unit accounting heat rates for 2005. For the years 2006-2013, PROMOD internally calculates the previous year’s annual average heat rate to use for the current year’s accounting heat rate for the purpose of billing exchange energy.

MERCHANT GENERATION

- A total of 19,816 MW of merchant unit generation based on System Planning's Forecasting and Analysis March 5, 2004 base case outlook became the starting point for our analysis. Adjustments were made to that total to reflect border plants, cogeneration customers and cancelled plants. The result of these adjustments resulted in the merchant plant modeling assumption of 13,830.5 net MW.
- Other new build capacity (2002 forward) was adjusted to net out the load forecast for that location, leaving only the "merchant" capacity available for dispatch in PROMOD.
- A forced outage rate of 5% was modeled. Minimum downtime/runtime is 8/16 (representing on-peak and off-peak hours) for combined cycle and 1/1 for combustion turbine merchant units. The mean time to repair was input as 8 hours.
- Generation Planning split the merchant generation into 8 different unit configurations, which consisted of 4 types of CTs, 3 types of CCs, and 1 type of Cogen. There was a heat rate at full load for each of the 8 unit configurations. An additional adjustment was made to the merchant units heat rates using the heat rate performance factor input. This adjustment was received from Northbridge to take into account the bidding behavior of the merchant plants.
- Generation Planning provided startup cost and variable O&M cost (roughly \$1/MWh) utilized in the model.
- A merchant company (Merchco) was established, owning 100% of all merchant generation. Unit purchase transactions were set up for each merchant unit (and EPI's portion of Independence 2 and Ritchie 2) to allow Entergy to purchase the energy that Merchco does not sell off-system. These transactions are treated as joint account purchases and, as such, are split among the Operating Companies by responsibility ratio for all plants except those characterized as Cogen. The purchase transactions characterized as Cogen are assigned to a specific Operating Company based on the location of the cogeneration facility. The price of the energy sold to Entergy is the bus price for this unit.
- Uplift (dollars) is calculated outside the model by calculating the difference between the merchant unit operating cost (calculated from average heat rate + startup cost + variable O&M cost) and market price (merchant unit transaction price based on incremental heat rate). The COGEN merchant plants are omitted from the calculation. The effect of 125% and 110% heat rate performance factor inputs are excluded. The random heat rate performance factor is included in the calculation. The distribution to Operating Company is based on native load (EAI includes the little 3 co-owners). Merchant unit profit is ignored in the calculation.

MERCHANT GENERATION

Below is a map of the Entergy Market Region new builds assumed in PROMOD:



MERCHANT GENERATION

- Capacity Additions by transmission region, in gross MWs, for the Entergy Market Region are displayed below:

Base Case (Most Likely Scenario) - NewBuild Capacity in Annual Gross MW by Online Year

PlanArea	1999	2000	2001	2002	2003	2004	2005	Grand Total
E_AMITE	0	0	0	770	0	0	0	770
E_CENT	352	1,612	2,035	4,318	4,543	989	700	14,549
E_NARK	0	0	224	550	0	0	0	774
E_WOTAB	19	605	665	745	1,200	0	489	3,723
Grand Total	371	2,217	2,924	6,383	5,743	989	1,189	19,816

This is the starting point for the data input into PROMOD. Reductions were made to this total to reflect the fact that certain plants reside on the border more than one control area, some of these plants are cogeneration facilities and, therefore, total plant capacity was reduced by an assumed load at that facility or those facilities are already reflected as a cogen purchase in PROMOD. The adjusted totals are reflected on the following two pages.

(THE PLANT NAMES, CAPACITY, AND COMMENTS HAVE BEEN REDACTED FROM THE TABLE BELOW)

MERCHANT GENERATION

PROMOD Plant Name	PROMOD Unit Num	Modeled Capacity	Comment	PROMOD Area ID	Commission Date	Resource Plan Detail
Total Amite South	1	_____		14	1/1/2003	
	1			3	1/1/2003	
	1			1	1/1/2003	
	1			3	1/1/2003	
	1			2	1/1/2003	
	1			2	1/1/2003	
	1			15	1/1/2003	
	1			2	1/1/2003	
	5			3	1/1/2003	
	2			1	1/1/2003	
	1			2	1/1/2003	
	1			15	1/1/2003	
	2			3	1/1/2003	
	2			15	1/1/2003	
	2			1	1/27/2003	
	3			1	4/18/2003	
	4			1	5/10/2003	
	1			15	6/15/2003	
	5			1	6/19/2003	
	1			2	7/8/2003	
	1			15	3/18/2004	
	1			15	11/1/2004	
	2			2	5/1/2004	
	1	_____		1	1/1/2005	
Total Central						
	1	_____		1	1/1/2003	

Total North Arkansas

MERCHANT GENERATION

PROMOD Plant Name	PROMOD Unit Num	Modeled Capacity	Comment	PROMOD Area ID	Commission Date	Resource Plan Detail
	1			4	1/1/2003	
	2			4	1/1/2003	
	1			5	5/1/2004	
	1			4	1/1/2003	
	4			4	1/1/2003	
	1			5	5/1/2003	
	2			5	5/1/2003	
	1			5	6/1/2005	
Total WOTAB		<hr/>				
Total Merchants		<hr/>				

RETIREMENTS

- Only the retirement of Paterson 4, effective March 1, 2003, was modeled in this study.

GAS FORECAST

- The gas forecast in PROMOD is based on the Henry Hub gas forecast from April 2, 2004, corporate gas forecast (April 2004 corporate PE) prepared by Forecasting and Analysis group.
- The annual Henry Hub price from System Planning's forecast is as follows: **(THE HENRY HUB FORECAST AND METHODOLOGY USED TO PRODUCE IT HAS BEEN REDACTED)**

- -
 -
 -
 - Using the above Henry Hub forecast, EMO's Resource Planning developed a "delivered to plant" gas forecast using the following methodology:
 - For EGSI's generating plants located in Texas, the Houston Ship Channel (HSC) is the appropriate market center. The spot gas forecast for the HSC was based on the historic difference ("basis") between the Henry Hub and HSC. A monthly basis forecast was developed from this historic difference and applied to the forecasted Henry Hub price to arrive at the forecasted spot gas price in the Houston Ship Channel. The projected delivered price of fuel was calculated using the projected index price (Henry Hub or Houston Ship Channel) and any applicable transportation costs, taxes, and, in the case of Evangeline, contract adders/fees.

OIL FORECAST

- A corporate oil price forecast was received from Forecasting and Analysis group on April 6, 2004. The forecasted price was adjusted for transportation and state sales taxes. This formed the basis for determining the dispatch price for oil. Oil burn is limited to Lynch 4, Paterson 5, and Rex Brown 5. The forecast is as follows: **(THE OIL PRICE FORECAST FOR 2003-2013 HAS BEEN REDACTED FROM THE TABLE BELOW)**

2003
2004
2005
2006
2007
2008
2009
2010
2011
2012
2013

- The oil billing price is based on the projected cost of oil burned out of inventory. The following assumptions are made in the oil inventory forecast:
 1. Most recent actual oil inventory accounting summary was provided by Fuel Accounting, and this serves as the starting point for the inventory forecast.
 2. EGS maintains its own fuel oil inventory. Fuel oil for all other operating companies is managed by SFI.
 3. Oil inventories were maintained by oil type, and all oil was aggregated by type. For example, all #2 oil at EGS plants is aggregated for inventory accounting purposes, regardless of which plant the oil is physically located. Likewise, all #6 EGS oil was aggregated for inventory accounting purposes. This same accounting treatment was followed for SFI oil.
 4. If firm oil purchases can be identified, these are included in the inventory forecast, both as to volume and price.
 5. Projected oil burns were provided by PMA based on projected dispatch gas and oil prices.
 6. It was assumed that oil is purchased in the same volumes as the projected quantities burned. This ensures that oil inventory levels remain unchanged. The price of oil purchased is determined on the basis of the projected spot oil price, including transportation and taxes.

COAL FORECAST

- Forecasts of the individual components of the delivered cost of coal were prepared for White Bluff, Independence, and Nelson 6. The individual components included the commodity cost of coal, the cost of transportation, and other coal-related costs such as the cost of company-owned or lease railcars, the operating and maintenance costs associated with coal handling and ash disposal equipment. The forecast for delivered coal costs for Entergy's ownership share of Big Cajun 2, Unit 3 was prepared on a total delivered cost basis because the Company only is provided the sum of coal transportation, coal car, and car maintenance costs by Louisiana Generating, the majority owner of that facility. The commodity coal cost forecast was provided by Global Insights (formerly WEFA). The forecast for other cost components was based on contract specific terms and conditions or historical data. The coal price forecast was provided by Forecasting and Analysis group on April 16, 2004.
- A ten-year monthly coal burn assumption for ISES, White Bluff, and Nelson 6 was received from the coal group to develop the fuel limits. For the coal units that burn a combination of contract and spot coal (ISES and White Bluff), the coal group calculated a percentage of total burn by year that would come from contract coal and applied that factor to each month's forecast to get a monthly burn quantity split between contract and spot coal. Generation Planning developed an inventory price that approximated current coal inventory accounting procedures and then gave PMA a single monthly price (calculated from the contract and spot burn quantities and the amount of assumed coal in inventory that would be burned) by unit to be used as the coal billing price.
- A ten-year monthly coal burn was also received for Cajun.

NUCLEAR FORECAST

- The nuclear fuel price forecast, planned maintenance/refueling schedule, heat rates, and capacity changes/uprates were provided by the Nuclear Fuels group. The following is the case description provided by the nuclear fuels group:

Item	Description
Date:	April 1, 2004
Case:	RP-2004-V1
Schedule:	EN-South Official Schedule 2004 Update #3 Draft A (typically 25 day outages and 98% LF) to be approved. Shutdown and startups at MIDNIGHT (24:00) of stated outage start and end date. RBS outages assumed to start at Noon in these cases. Actual outage start times are scheduled by day ahead planning process.

- 10 percent of Grand Gulf capacity is modeled as a unit participation sale (representing the SMEPA ownership portion).
- Coast down data, which is the data that is used to replicate the operation of a unit prior to a nuclear refueling outage, is modeled as a capacity derate in PROMOD prior to the applicable refueling outage for those units such data was provided.
- The mean time to repair (average forced downtime hours) input was derived based upon the following calculation: $(8760 \text{ [annual hours]} * .02 \text{ [annual forced outage rate]}) / 2 \text{ [number of startups]}$.
- Minimum downtime and runtime inputs were based on an estimate from the nuclear fuels group.

SO2 EMISSIONS

- SO2 emissions allowance price forecast was received from the Forecasting and Analysis group, based on Global Insight's short-term and long term forecast of March 3, 2004.
- Coal unit emission rates (provided by Generation Planning) are based on 2002 historical data from the environmental group and assumptions surrounding the type of coal that would be burned during the forecast period. Cajun historical data was provided for 2002.
- Oil unit emission rates (also provided by Generation Planning) were a theoretical value based on historical data, and the assumption that we would burn 1% oil.
- From these inputs (the price of SO₂ allowances and unit emission rates), PROMOD adds a dispatch fee to the price of oil and coal.

ECONOMY PRICE FORECAST

Generation Planning developed an hourly economy price forecast (April 2004 forecast) using the following methodology:

(THE METHODOLOGY USED TO PRODUCE THE ECONOMY PRICE FORECAST HAS BEEN REDACTED)

?

(THE PRICE FORECAST RESULTS HAVE BEEN REDACTED FROM THE TABLE BELOW)

ECONOMY PRICE FORECAST

- The price projections, on an annual basis by subperiod, are as follows:

Southern Company \$/MWh			
Subperiod	Weekday	Weeknight	Weekend
2005			
2006			
2007			
2008			
2009			
2010			
2011			
2012			
2013			

TVA \$/MWh			
Subperiod	Weekday	Weeknight	Weekend
2005			
2006			
2007			
2008			
2009			
2010			
2011			
2012			
2013			

Southern Company Implied Heatrate			
Subperiod	Weekday	Weeknight	Weekend
2005			
2006			
2007			
2008			
2009			
2010			
2011			
2012			
2013			

TVA Implied Heatrate			
Subperiod	Weekday	Weeknight	Weekend
2005			
2006			
2007			
2008			
2009			
2010			
2011			
2012			
2013			

TRANSACTIONS

- Hydro
 - Energy - Blakely/Degray, Remmel and Carpenter, and Toledo Bend energy was modeled based on the 2001 and 2002 monthly energy from the intra-system billing records. Vidalia was calculated based on a twelve year average from 1991-2002
 - Capacity – Remmel, Carpenter, and Vidalia capacity are based on the summer 2003 and winter 2002-2003 approved ratings from Generation Planning. Toledo Bend was modeled as 69 MW representing Entergy's 75% ownership of the unit. Blakely/Degray purchase is modeled as 164 MW, while the sale is 143 MW.
 - Energy Cost – Toledo Bend is modeled with a \$21/MWh energy cost per the contract. Blakely/Degray, Remmel, and Carpenter have an energy cost of \$0/MWh. Vidalia is modeled per its contract as follows:

Vidalia Energy Cost	
Year	\$/MWh
1989-1996	65.00
1997	75.00
1998	85.00
1999	100.00
2000	120.00
2001	125.00
2002	130.00
2003	135.00
2004	145.00
2005	155.00
2006	160.00
2007	170.00
2008	180.00
2009	195.00
2010-2013	205.00

TRANSACTIONS

- Cogeneration
 - Cogeneration purchases were modeled as a company specific purchase in PROMOD.
 - The energy was based on 12 months (8/1/02-7/31/03) of historical data from ISB, which includes total cogen purchased by company by month.
 - The corresponding peak, also obtained from ISB as the monthly maximum purchased, was averaged monthly and input as the contract's maximum capacity
 - Cogeneration energy was priced at the hourly Entergy zonal price. The price assumed corresponds to the hour in which the energy produced by a cogeneration facility "put" energy to the System
- Economy purchases and sales
 - Economy purchase and sales transactions representing seven external interface locations were modeled.
 - Joint account purchases and sales were priced using one of the two zonal hourly price curves according to the bus location of the transaction.
 - Joint account purchases were split among the Entergy Operating Companies by responsibility ratio in accordance with the System Agreement
- Exchange
 - This is the energy that is exchanged among the Entergy Operating Companies. PROMOD performs a total system dispatch for Entergy. If in any hour, an Operating Company has more generation dispatched than its load, then it is referred to as a "long" Company, although this is not a long Company within the meaning of MSS-1. If a company has less generation dispatched than its load, then it is referred to as a "short" Company, although this is not a short Company within the meaning of MSS-1. The "long" Company's extra energy is allocated to a pool of energy called the Exchange. The "short" Company is allocated its needed energy from the Exchange at a price set by MSS-3.
 - It was assumed that EGS-TX would move to competition in July 2005. After this date, EGS-TX no longer would participate in the exchange; however, dispatch still occurred as a total system. EGS-TX continued to sell to or buy from the rest of the Entergy system. The energy was priced at a load-weighted market price for the region.

TRANSACTIONS

- Co-Owner (The Arkansas Co-Owners represented here are AECC, ETEC, Conway, West Memphis, Osceola, and Jonesboro)
 - Performance Entitlement
 - This transaction represents the amount of energy that each Co-Owner is entitled based on the generation from its share of the unit(s) in question and the terms of the contract. This energy is priced pursuant to their ownership agreement.
 - Substitute
 - This transaction represents the amount of energy each Co-Owner is entitled to that does not come from the co-owned units because of the dispatch decision of the majority owner of the unit. For example, if a co-owned unit is not running at maximum because of Entergy's economic dispatch decisions, but is available at maximum, the Co-Owner is entitled to its ownership share of the output of that unit based on the maximum capacity of the co-owned unit. Therefore, some of the energy will be supplied by the co-owned unit and some will come from other EAI resources. All of the energy is priced as if it came from the unit.
 - Replacement
 - This transaction represents the amount of energy above entitlement which the Co-Owner needs from Entergy to supply the energy portion of the Co-Owner's load based on the terms of the contract. This energy is priced based on the terms of the contract and is different for each Co-Owner.
 - Excess
 - The transaction represents the amount of energy that Entergy is required to purchase back from the Co-Owner. For example, if the Co-Owner load is less than the amount of energy they receive through performance entitlement, then Entergy is required to buy back the energy. The energy is priced based on the terms of the contract and is different for each Co-Owner. This energy is referred to as excess purchase energy. The AECC excess energy is treated as a joint account purchase for the System. All other Co-Owners excess energy is treated as a company specific purchase to EAI.

SECURITY REGION DATA

The following security region data is modeled in the current PROMOD database:

- A minimum of one unit at Lewis Creek must be committed at all times due to voltage support. Furthermore, Lewis Creek 1 and Lewis Creek 2 must be committed during summer for voltage support. (Group A in PROMOD data)
- Sabine 4 or Sabine 5 (on 230 kV bus) must be committed due to voltage problems. (Group B in PROMOD data)
- At least two of the following four units should be committed due to potential line loading and voltage problems in Lake Charles area during contingencies. Nelson 4, Nelson 6, Sabine 4, and Sabine 5. Also three of these four units are needed for voltage support during summer and winter peak seasons. (Group C in PROMOD data)
- At least two of the following three units are required to be committed for voltage support problems. Sabine 1, Sabine 2, or Sabine 3. (Group D PROMOD data)
- Rex Brown 4 must be committed any time the EMI load is above 1,800 MW. If Rex Brown 4 is not available, Rex Brown 3 should be committed. This occurs usually in the months May through September. (Group F in PROMOD data)
- The tables on the following pages explain the operation of these 3 units. Michoud 3, Ninemile 4, Ninemile 5 (Group E in PROMOD data)
- The following tables were also used to determine the input for the following five units. At least one unit should be committed due to voltage problems during contingencies at all times. Michoud 1, Michoud 2, Ninemile 1, Ninemile 2, Ninemile 3 (Group G in PROMOD data).

§

SECURITY REGION DATA

For January 2005-May 2006

		115 kV Unit capacity factor (%)			
		75-100	50-74	10-49	0-9
230 kV Requirement	2 out 3	DSG Load 2540-3020	DSG Load 2380-2780	DSG Load 2180-2540	DSG Load 2120-2440
	3 out 3	DSG Load 3020-3500	DSG Load 2780-3260	DSG Load 2540-3040	DSG Load 2440-2930

Notes:

Apply this requirement for the months that exceeds the DSG load level and desired capacity factor on 115 kV units for more than 200 hours

This document supersedes the existing RMR requirement on the DSG 230 kV generating facilities (Ninemile 4, Ninemile 5 & Michoud 3)

This analysis assumes DSG load to be approximately 56% of Amite South load

SECURITY REGION DATA

For June 2006-December 2009

		115 kV Unit capacity factor (%)			
		75-100	50-74	10-49	0-9
230 kV Requirement	1 out 3	DSG Load 3704-4209	DSG Load 3526-4035	DSG Load 3228-3780	DSG Load 3141-3706
	2 out 3	DSG Load 4210-4716	DSG Load 4036-4550	DSG Load 3781-4269	DSG Load 3707-4160
	3 out 3	DSG Load 4717	DSG Load 4551	DSG Load 4270	DSG Load 4161

Notes:

Apply this requirement for the months that exceeds the DSG load level and desired capacity factor on 115 kV units for more than 200 hours

This document supersedes the existing RMR requirement on the DSG 230 kV generating facilities (Ninemile 4, Ninemile 5 & Michoud 3)

This analysis assumes DSG load to be approximately 56% of Amite South load

TRANSMISSION

- The PROMOD IV model has the distinct advantage of modeling a full DC load flow representation that allows the user to dispatch under electrical grid properties. One of the features of this representation is the model's ability to adhere to flow limits across specified lines and interfaces.
- In order to take advantage of this feature in PROMOD, the PMA group had to download a PSS/E load flow case from the Transmission OASIS site and convert it into PROMOD format. The Summer 2004 load flow scenario was chosen from this site. Once downloaded and converted into PROMOD certain "adjustments" had to be made such as:
 - Assign each operating company a power flow zone:
 - Entergy Arkansas, Inc., EAI - 106, 107, 108 (only the non co-owner busses were assigned to EAI.
 - Entergy Louisiana, Inc., ELI - 55, 100, 105
 - Entergy Mississippi, Inc., EMI - 102, 103, 104
 - Entergy New Orleans, Inc., ENOI - 101
 - Entergy Gulf States, Inc. Louisiana, EGSI-LA - 53, 54
 - Entergy Gulf States, Inc. Texas, EGSI-TX - 50, 51, 52
 - Map each generator and transaction to specific generator busses
 - Input non-conforming load at each load bus. Non-conforming load represents a constant load at a load bus and typically is representative of industrial load. PROMOD takes the current total Company loads (less the non-conforming load) and allocates the load to each bus using the percentage of Summer 2004 PSSE load at each bus (less any non-conforming load at that bus) to total company Summer 2004 load.
 - Model a transmission upgrade that increases the Amite South Interface import constraint.
 - Add busses to the power flow data to model the non-Entergy portion of Nelson 6, Grand Gulf, and Cajun 2 Unit 3.
- Based on the DSG transmission upgrades, the interface import limit was increased from 1953 to 2218 MW.
- The following interface definitions were modeled.
 - The Amite South interface is modeled in the event file and monitors the flow to ensure that the Amite South import/export does not exceed 2,370/1,000 MW respectively
 - The WOTAB (West of the Achafalaya Basin) interface is modeled in the event file and monitors the flow to ensure that the WOTAB import/export does not exceed 1,800/1,500 MW respectively
 - The Western interface is modeled in the event file and monitors the flow to ensure that the Western import/export does not exceed 1000/1000 MW respectively
 - The DSG interface is modeled in the event file and monitors the flow to ensure that the DSG import/export does not exceed 2218/9999 MW respectively

TRANSMISSION

- Seventy one contingencies were modeled. All 500, 345, and 230 KV lines were monitored in addition to other possibly constrained lines. Internal interface limits were defined for the Amite South, WOTAB, DSG, and Western regions. Two DC ties that were not included in the power flow data were added to connect Northern Manitoba and Hydro Quebec to the Eastern Interconnect.
- The following joint account purchase and sale limits, provided by Transmission, were input into PROMOD:

Transaction	Bus	Control Area	Winter	Spring	Summer	Fall
JP-EAIN1	30214	AMRN	488	420	375	444
JP-EMIN	18434	TVA	488	420	375	444
JP-EMIN	18274	TVA	488	420	375	444
JP-EMIS	15104	SOCO	650	560	500	592
JP-EMIS	15132	SOCO	650	560	500	592
JP-EMIS	15107	SOCO	650	560	500	592
JP-WOTAB	55224	OGE	488	420	375	444
Total Import			3902	3361	3000	3554
Transaction	Bus	Control Area	Winter	Spring	Summer	Fall
JS-EAIN1	30214	AMRN	325	280	250	296
JS-EMIN	18434	TVA	325	280	250	296
JS-EMIN	18274	TVA	325	280	250	296
JS-EMIS	15104	SOCO	434	373	333	395
JS-EMIS	15132	SOCO	434	373	333	395
JS-EMIS	15107	SOCO	434	373	333	395
JS-WOTAB	55224	OGE	325	280	250	296
Total Export			2601	2241	2000	2370

SIMULATION PARAMETERS

- Simulation Period: January 2005 to December 2013

APPENDIX E

PROMOD IV HMC Transmission Results [Redacted]

APPENDIX F

**Transmission map indicating location of
examined transmission projects**

APPENDIX G

**Detailed analyses showing the determination
of the net impact over the study period
[Redacted]**

ENTERGY SYSTEM

TRANSMISSION PROJECTS COST/BENEFIT ANALYSIS COMPARISON OF WITH DSG CASE WITH STUDY BASE CASE : Lower Bound

TABLE OF CONTENTS

	<u>PAGE NO.</u>
SUMMARY OF NET IMPACTS	1
PROJECT REVENUE REQUIREMENT	2-16
CHANGE IN FUEL AND PURCHASED POWER COSTS	17-19
NET IMPACT 2005-2026	20-22
REVENUE REQUIREMENT - ELI UNDER 230kV	23
REVENUE REQUIREMENT - ENO UNDER 230kV	24
REVENUE REQUIREMENT - OVER 230kV	25

**ENTERGY SYSTEM
TRANSMISSION REVENUE REQUIREMENT ANALYSIS
SUMMARY OF RESULTS
NET PRESENT VALUE-2004 THROUGH 2026
(\$1,000)**

Item	EAI	ELI	EMI	ENO	EGS-LA	EGS-TX	Entergy
Increase in Fixed Costs	\$18,966	\$47,722	\$12,726	\$6,200	\$15,629 #	\$14,211 #	\$115,453
Change in Fuel and Purchased Power Costs	\$7,442	(\$157,346)	(\$31,675)	(\$51,732)	(\$28,379) #	\$12,369 #	(\$249,322)
Net Impact	\$26,407	(\$109,624)	(\$18,949)	(\$45,532)	(\$12,750)	\$26,579	(\$133,868)

ENTERGY SYSTEM
TRANSMISSION REVENUE REQUIREMENT ANALYSIS
(\$1,000)

ELI-230

Project Nos. 1 & 9

Year	Gross Investment	Depreciation	Deferred Income taxes	Accumulated Depreciation	Accumulated Reserve for DIT	Average Net Investment
2002						
2003						
2004						
2005	23,372 #	302	334	302	334	11,368
2006	23,372 1	521	643	823	977	22,154
2007	23,372 1	521	595	1,345	1,572	21,014
2008	23,372 1	521	550	1,866	2,122	19,920
2009	23,372 1	521	509	2,387	2,631	18,869
2010	23,372 1	521	471	2,908	3,101	17,858
2011	23,372 1	521	435	3,429	3,537	16,884
2012	23,372 1	521	403	3,951	3,939	15,944
2013	23,372 1	521	397	4,472	4,337	15,023
2014	23,372 1	521	397	4,993	4,734	14,104
2015	23,372 1	521	397	5,514	5,131	13,186
2016	23,372 1	521	397	6,035	5,529	12,267
2017	23,372 1	521	397	6,557	5,926	11,348
2018	23,372 1	521	397	7,078	6,324	10,430
2019	23,372 1	521	397	7,599	6,721	9,511
2020	23,372 1	521	397	8,120	7,118	8,593
2021	23,372 1	521	397	8,641	7,516	7,674
2022	23,372 1	521	397	9,163	7,913	6,756
2023	23,372 1	521	397	9,684	8,310	5,837
2024	23,372 1	521	397	10,205	8,708	4,919
2025	23,372 1	521	199	10,726	8,906	4,099
2026	23,372 1	521	-	11,247	8,906	3,479

ENTERGY SYSTEM
TRANSMISSION REVENUE REQUIREMENT ANALYSIS
(\$1,000)

ELI-230

Project Nos. 2, 3, 11, & 14

Year	Gross Investment	Depreciation	Deferred Income taxes	Accumulated Depreciation	Accumulated Reserve for DIT	Average Net Investment
2002						
2003						
2004						
2005						
2006						
2007	35,600	1 794	206	794	206	17,300
2008	35,600	1 794	677	1,588	883	33,865
2009	35,600	1 794	603	2,382	1,486	32,431
2010	35,600	1 794	535	3,176	2,022	31,067
2011	35,600	1 794	473	3,969	2,494	29,770
2012	35,600	1 794	414	4,763	2,909	28,532
2013	35,600	1 794	361	5,557	3,269	27,351
2014	35,600	1 794	311	6,351	3,580	26,221
2015	35,600	1 794	303	7,145	3,883	25,120
2016	35,600	1 794	303	7,939	4,186	24,024
2017	35,600	1 794	303	8,733	4,488	22,927
2018	35,600	1 794	303	9,527	4,791	21,831
2019	35,600	1 794	303	10,320	5,094	20,734
2020	35,600	1 794	303	11,114	5,397	19,637
2021	35,600	1 794	303	11,908	5,699	18,541
2022	35,600	1 794	303	12,702	6,002	17,444
2023	35,600	1 794	303	13,496	6,305	16,348
2024	35,600	1 794	303	14,290	6,608	15,251
2025	35,600	1 794	303	15,084	6,910	14,154
2026	35,600	1 794	303	15,878	7,213	13,058

ENTERGY SYSTEM
TRANSMISSION REVENUE REQUIREMENT ANALYSIS
(\$1,000)

ELI-115

Project Nos. 4, 5, 6, & 17

Year	Gross Investment	Depreciation	Deferred Income taxes	Accumulated Depreciation	Accumulated Reserve for DIT	Average Net Investment
2002						
2003						
2004						
2005						
2006						
2007	15,000	1 335	87	335	87	7,289
2008	15,000	1 335	285	669	372	14,269
2009	15,000	1 335	254	1,004	626	13,665
2010	15,000	1 335	226	1,338	852	13,090
2011	15,000	1 335	199	1,673	1,051	12,543
2012	15,000	1 335	175	2,007	1,226	12,022
2013	15,000	1 335	152	2,342	1,378	11,524
2014	15,000	1 335	131	2,676	1,509	11,048
2015	15,000	1 335	128	3,011	1,636	10,584
2016	15,000	1 335	128	3,345	1,764	10,122
2017	15,000	1 335	128	3,680	1,891	9,660
2018	15,000	1 335	128	4,014	2,019	9,198
2019	15,000	1 335	128	4,349	2,146	8,736
2020	15,000	1 335	128	4,683	2,274	8,274
2021	15,000	1 335	128	5,018	2,401	7,812
2022	15,000	1 335	128	5,352	2,529	7,350
2023	15,000	1 335	128	5,687	2,657	6,888
2024	15,000	1 335	128	6,021	2,784	6,426
2025	15,000	1 335	128	6,356	2,912	5,964
2026	15,000	1 335	128	6,690	3,039	5,502

ENTERGY SYSTEM
TRANSMISSION REVENUE REQUIREMENT ANALYSIS
(\$1,000)

ENO-230

Project No. 7

Year	Gross Investment	Depreciation	Deferred Income taxes	Accumulated Depreciation	Accumulated Reserve for DIT	Average Net Investment
2002						
2003						
2004	1,900 #	24.6	11.0	25	11	932
2005	1,900 1	42.4	36.1	67	47	1,825
2006	1,900 1	42.4	32.2	109	79	1,749
2007	1,900 1	42.4	28.6	152	108	1,676
2008	1,900 1	42.4	25.2	194	133	1,607
2009	1,900 1	42.4	22.1	236	155	1,541
2010	1,900 1	42.4	19.2	279	174	1,478
2011	1,900 1	42.4	16.6	321	191	1,417
2012	1,900 1	42.4	16.2	364	207	1,358
2013	1,900 1	42.4	16.2	406	223	1,300
2014	1,900 1	42.4	16.2	448	240	1,241
2015	1,900 1	42.4	16.2	491	256	1,183
2016	1,900 1	42.4	16.2	533	272	1,124
2017	1,900 1	42.4	16.2	575	288	1,066
2018	1,900 1	42.4	16.2	618	304	1,007
2019	1,900 1	42.4	16.2	660	320	949
2020	1,900 1	42.4	16.2	702	336	890
2021	1,900 1	42.4	16.2	745	353	832
2022	1,900 1	42.4	16.2	787	369	773
2023	1,900 1	42.4	16.2	830	385	715
2024	1,900 1	42.4	-	872	385	664
2025	1,900 1	42.4	-	914	385	622
2026	1,900 1	42.4	-	957	385	580

ENTERGY SYSTEM
TRANSMISSION REVENUE REQUIREMENT ANALYSIS
(\$1,000)

ELI-230**Project No. 8**

Year	Gross Investment		Depreciation	Deferred Income taxes	Accumulated Depreciation	Accumulated Reserve for DIT	Average Net Investment
2002							
2003							
2004	1,900	#	24.57	11.01	25	11	932
2005	1,900	1	42.37	36.12	67	47	1,825
2006	1,900	1	42.37	32.20	109	79	1,749
2007	1,900	1	42.37	28.57	152	108	1,676
2008	1,900	1	42.37	25.22	194	133	1,607
2009	1,900	1	42.37	22.12	236	155	1,541
2010	1,900	1	42.37	19.25	279	174	1,478
2011	1,900	1	42.37	16.59	321	191	1,417
2012	1,900	1	42.37	16.16	364	207	1,358
2013	1,900	1	42.37	16.16	406	223	1,300
2014	1,900	1	42.37	16.16	448	240	1,241
2015	1,900	1	42.37	16.16	491	256	1,183
2016	1,900	1	42.37	16.16	533	272	1,124
2017	1,900	1	42.37	16.16	575	288	1,066
2018	1,900	1	42.37	16.16	618	304	1,007
2019	1,900	1	42.37	16.16	660	320	949
2020	1,900	1	42.37	16.16	702	336	890
2021	1,900	1	42.37	16.16	745	353	832
2022	1,900	1	42.37	16.16	787	369	773
2023	1,900	1	42.37	16.16	830	385	715
2024	1,900	1	42.37	-	872	385	664
2025	1,900	1	42.37	-	914	385	622
2026	1,900	1	42.37	-	957	385	580

ENTERGY SYSTEM
TRANSMISSION REVENUE REQUIREMENT ANALYSIS
(\$1,000)

ELI-115

Project No. 10, 12, & 13

Year	Gross Investment		Depreciation	Deferred Income taxes	Accumulated Depreciation	Accumulated Reserve for DIT	Average Net Investment
2002							
2003							
2004							
2005	3,600	#	47	21	47	21	# 1,766
2006	3,600	1	80	68	127	89	# 3,458
2007	3,600	1	80	61	207	150	# 3,313
2008	3,600	1	80	54	287	204	# 3,175
2009	3,600	1	80	48	368	252	# 3,044
2010	3,600	1	80	42	448	294	# 2,919
2011	3,600	1	80	36	528	331	# 2,800
2012	3,600	1	80	31	609	362	# 2,685
2013	3,600	1	80	31	689	393	# 2,574
2014	3,600	1	80	31	769	423	# 2,463
2015	3,600	1	80	31	849	454	# 2,352
2016	3,600	1	80	31	930	484	# 2,241
2017	3,600	1	80	31	1,010	515	# 2,130
2018	3,600	1	80	31	1,090	546	# 2,020
2019	3,600	1	80	31	1,170	576	# 1,909
2020	3,600	1	80	31	1,251	607	# 1,798
2021	3,600	1	80	31	1,331	638	# 1,687
2022	3,600	1	80	31	1,411	668	# 1,576
2023	3,600	1	80	31	1,492	699	# 1,465
2024	3,600	1	80	31	1,572	729	# 1,354
2025	3,600	1	80	-	1,652	729	# 1,259
2026	3,600	1	80	-	1,732	729	# 1,178

ENTERGY SYSTEM
TRANSMISSION REVENUE REQUIREMENT ANALYSIS
(\$1,000)

ENO-230

Project No. 21

Year	Gross Investment	Depreciation	Deferred Income taxes	Accumulated Depreciation	Accumulated Reserve for DIT	Average Net Investment
2002						
2003						
2004						
2005	1,685	22	10	22	10 #	827
2006	1,685	38	32	59	42 #	1,619
2007	1,685	38	29	97	70 #	1,551
2008	1,685	38	25	135	96 #	1,486
2009	1,685	38	22	172	118 #	1,425
2010	1,685	38	20	210	138 #	1,366
2011	1,685	38	17	247	155 #	1,310
2012	1,685	38	15	285	169 #	1,257
2013	1,685	38	14	322	184 #	1,205
2014	1,685	38	14	360	198 #	1,153
2015	1,685	38	14	398	212 #	1,101
2016	1,685	38	14	435	227 #	1,049
2017	1,685	38	14	473	241 #	997
2018	1,685	38	14	510	255 #	945
2019	1,685	38	14	548	270 #	893
2020	1,685	38	14	585	284 #	841
2021	1,685	38	14	623	298 #	790
2022	1,685	38	14	661	313 #	738
2023	1,685	38	14	698	327 #	686
2024	1,685	38	14	736	341 #	634
2025	1,685	38	-	773	341 #	589
2026	1,685	38	-	811	341 #	552

ENTERGY SYSTEM
TRANSMISSION REVENUE REQUIREMENT ANALYSIS
(\$1,000)

ENO-115

Project No. 15

Year	Gross Investment		Depreciation	Deferred Income taxes	Accumulated Depreciation	Accumulated Reserve for DIT	Average Net Investment
2002							
2003							
2004							
2005							
2006	1,012	##	13	6	13	6	497
2007	1,012	1	23	19	36	25	972
2008	1,012	1	23	17	58	42	931
2009	1,012	1	23	15	81	57	893
2010	1,012	1	23	13	103	71	856
2011	1,012	1	23	12	126	83	821
2012	1,012	1	23	10	148	93	787
2013	1,012	1	23	9	171	102	755
2014	1,012	1	23	9	194	110	724
2015	1,012	1	23	9	216	119	692
2016	1,012	1	23	9	239	128	661
2017	1,012	1	23	9	261	136	630
2018	1,012	1	23	9	284	145	599
2019	1,012	1	23	9	306	153	568
2020	1,012	1	23	9	329	162	537
2021	1,012	1	23	9	352	171	505
2022	1,012	1	23	9	374	179	474
2023	1,012	1	23	9	397	188	443
2024	1,012	1	23	9	419	196	412
2025	1,012	1	23	9	442	205	381
2026	1,012	1	23	-	464	205	354

ENTERGY SYSTEM
TRANSMISSION REVENUE REQUIREMENT ANALYSIS
(\$1,000)

ENO-230

Project No. 15

Year	Gross Investment		Depreciation	Deferred Income taxes	Accumulated Depreciation	Accumulated Reserve for DIT	Average Net Investment
2002							
2003							
2004							
2005					-	-	-
2006	1,517	#	20	9	20	9	744
2007	1,517	1	34	29	53	38	1,457
2008	1,517	1	34	26	87	63	1,396
2009	1,517	1	34	23	121	86	1,338
2010	1,517	1	34	20	155	106	1,283
2011	1,517	1	34	18	189	124	1,230
2012	1,517	1	34	15	223	139	1,180
2013	1,517	1	34	13	256	153	1,132
2014	1,517	1	34	13	290	165	1,085
2015	1,517	1	34	13	324	178	1,038
2016	1,517	1	34	13	358	191	991
2017	1,517	1	34	13	392	204	944
2018	1,517	1	34	13	426	217	898
2019	1,517	1	34	13	459	230	851
2020	1,517	1	34	13	493	243	804
2021	1,517	1	34	13	527	256	758
2022	1,517	1	34	13	561	269	711
2023	1,517	1	34	13	595	282	664
2024	1,517	1	34	13	629	294	617
2025	1,517	1	34	13	662	307	571
2026	1,517	1	34	-	696	307	530

ENTERGY SYSTEM
TRANSMISSION REVENUE REQUIREMENT ANALYSIS
(\$1,000)

ELI-115

Project No. 17

Year	Gross Investment	Depreciation	Deferred Income taxes	Accumulated Depreciation	Accumulated Reserve for DIT	Average Net Investment
2002						
2003						
2004						
2005						-
2006						-
2007	505 #	7	3	7	3	248
2008	505 1	11	10	18	13	485
2009	505 1	11	9	29	21	465
2010	505 1	11	8	40	29	445
2011	505 1	11	7	52	35	427
2012	505 1	11	6	63	41	409
2013	505 1	11	5	74	46	393
2014	505 1	11	4	85	51	377
2015	505 1	11	4	97	55	361
2016	505 1	11	4	108	59	346
2017	505 1	11	4	119	64	330
2018	505 1	11	4	130	68	314
2019	505 1	11	4	142	72	299
2020	505 1	11	4	153	77	283
2021	505 1	11	4	164	81	268
2022	505 1	11	4	175	85	252
2023	505 1	11	4	187	89	237
2024	505 1	11	4	198	94	221
2025	505 1	11	4	209	98	206
2026	505 1	11	4	221	102	190

ENTERGY SYSTEM
TRANSMISSION REVENUE REQUIREMENT ANALYSIS
(\$1,000)

ELI-230

Project No. 18

Year	Gross Investment	Depreciation	Deferred Income taxes	Accumulated Depreciation	Accumulated Reserve for DIT	Average Net Investment
2002						
2003						
2004						
2005						
2006						
2007	1,523 #	20	9	20	9	747
2008	1,523 1	34	29	54	38	1,463
2009	1,523 1	34	26	88	64	1,402
2010	1,523 1	34	23	122	86	1,343
2011	1,523 1	34	20	156	107	1,288
2012	1,523 1	34	18	190	124	1,235
2013	1,523 1	34	15	223	140	1,184
2014	1,523 1	34	13	257	153	1,136
2015	1,523 1	34	13	291	166	1,089
2016	1,523 1	34	13	325	179	1,042
2017	1,523 1	34	13	359	192	995
2018	1,523 1	34	13	393	205	948
2019	1,523 1	34	13	427	218	901
2020	1,523 1	34	13	461	231	854
2021	1,523 1	34	13	495	244	807
2022	1,523 1	34	13	529	257	761
2023	1,523 1	34	13	563	270	714
2024	1,523 1	34	13	597	283	667
2025	1,523 1	34	13	631	296	620
2026	1,523 1	34	13	665	309	573

ENTERGY SYSTEM
TRANSMISSION REVENUE REQUIREMENT ANALYSIS
(\$1,000)

Total All Projects			
Year	Average Net Investment	Depreciation Expense	Gross Investment
2002			
2003	-	-	-
2004	1,864	49	3,800
2005	16,785	434	32,457
2006	29,606	699	34,986
2007	53,240	1,837	87,614
2008	75,373	1,837	87,614
2009	71,983	1,837	87,614
2010	68,746	1,837	87,614
2011	65,652	1,837	87,614
2012	62,687	1,837	87,614
2013	59,826	1,837	87,614
2014	57,043	1,837	87,614
2015	54,301	1,837	87,614
2016	51,565	1,837	87,614
2017	48,828	1,837	87,614
2018	46,092	1,837	87,614
2019	43,356	1,837	87,614
2020	40,619	1,837	87,614
2021	37,883	1,837	87,614
2022	35,146	1,837	87,614
2023	32,410	1,837	87,614
2024	29,690	1,837	87,614
2025	27,101	1,837	87,614
2026	24,730	1,837	87,614

**ENTERGY SYSTEM
TRANSMISSION REVENUE REQUIREMENT ANALYSIS
(\$1,000)**

Total ELI Projects Under 230KV			
Year	Average Net Investment	Depreciation Expense	Gross Investment
2002			
2003			
2004			
2005	1,766	47	3,600
2006	3,458	80	3,600
2007	10,850	421	19,105
2008	17,929	426	19,105
2009	17,173	426	19,105
2010	16,455	426	19,105
2011	15,770	426	19,105
2012	15,117	426	19,105
2013	14,491	426	19,105
2014	13,888	426	19,105
2015	13,298	426	19,105
2016	12,709	426	19,105
2017	12,121	426	19,105
2018	11,532	426	19,105
2019	10,944	426	19,105
2020	10,355	426	19,105
2021	9,767	426	19,105
2022	9,178	426	19,105
2023	8,590	426	19,105
2024	8,001	426	19,105
2025	7,428	426	19,105
2026	6,870	426	19,105

ENTERGY SYSTEM
TRANSMISSION REVENUE REQUIREMENT ANALYSIS
(\$1,000)

Total ENO Projects Under 230KV			
Year	Average Net Investment	Depreciation Expense	Gross Investment
2002			
2003			
2004			
2005	-	-	-
2006	497	13	1,012
2007	972	23	1,012
2008	931	23	1,012
2009	893	23	1,012
2010	856	23	1,012
2011	821	23	1,012
2012	787	23	1,012
2013	755	23	1,012
2014	724	23	1,012
2015	692	23	1,012
2016	661	23	1,012
2017	630	23	1,012
2018	599	23	1,012
2019	568	23	1,012
2020	537	23	1,012
2021	505	23	1,012
2022	474	23	1,012
2023	443	23	1,012
2024	412	23	1,012
2025	381	23	1,012
2026	354	23	1,012

**ENTERGY SYSTEM
TRANSMISSION REVENUE REQUIREMENT ANALYSIS
(\$1,000)**

Total All Projects Over 230KV			
Year	Average Net Investment	Depreciation Expense	Gross Investment
2002			
2003			
2004	1,864	49	3,800
2005	15,018	387	28,857
2006	25,651	606	30,374
2007	41,418	1,393	67,497
2008	56,513	1,389	67,497
2009	53,916	1,389	67,497
2010	51,435	1,389	67,497
2011	49,061	1,389	67,497
2012	46,784	1,389	67,497
2013	44,581	1,389	67,497
2014	42,431	1,389	67,497
2015	40,311	1,389	67,497
2016	38,194	1,389	67,497
2017	36,077	1,389	67,497
2018	33,961	1,389	67,497
2019	31,844	1,389	67,497
2020	29,727	1,389	67,497
2021	27,611	1,389	67,497
2022	25,494	1,389	67,497
2023	23,377	1,389	67,497
2024	21,277	1,389	67,497
2025	19,292	1,389	67,497
2026	17,506	1,389	67,497

ENTERGY SYSTEM
TRANSMISSION REVENUE REQUIREMENT ANALYSIS
IMPACT ON FUEL AND PURCHASED POWER [DATA HAS BEEN REDACTED]

	EA!			(\$1,000) EL!			EMI		
	Base Case	Change Case	Change	Base Case	Change Case	Change	Base Case	Change Case	Change
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									
2014									
2015									
2016									
2017									
2018									
2019									
2020									
2021									
2022									
2023									
2024									
2025									
2026									

ENTERGY SYSTEM
TRANSMISSION REVENUE REQUIREMENT ANALYSIS
IMPACT ON FUEL AND PURCHASED POWER [DATA HAS BEEN REDACTED]

	ENO			EGS-LA			EGS-TX		
	Base Case	Change Case	Change	Base Case	Change Case	Change	Base Case	Change Case	Change
2002									
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									
2014									
2015									
2016									
2017									
2018									
2019									
2020									
2021									
2022									
2023									
2024									
2025									
2026									

ENTERGY SYSTEM
TRANSMISSION REVENUE REQUIREMENT ANALYSIS
IMPACT ON FUEL AND PURCHASED POWER [DATA HAS BEEN REDACTED]

(\$1,000)

ENTERGY

	Base Case	Change Case	Change
2002			
2003			
2004			
2005			
2006			
2007			
2008			
2009			
2010			
2011			
2012			
2013			
2014			
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			

TRANSMISSION REVENUE REQUIREMENT ANALYSIS
NET IMPACT [DATA HAS BEEN REDACTED]
(\$1,000)

Year	EAI			ELI			EMI		
	Increase In Fixed Costs	Change In Fuel & Purch Pw. Costs	Net Change In Costs	Increase In Fixed Costs	Change In Fuel & Purch Pw. Costs	Net Change In Costs	Increase In Fixed Costs	Change In Fuel & Purch Pw. Costs	Net Change In Costs
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									
2014									
2015									
2016									
2017									
2018									
2019									
2020									
2021									
2022									
2023									
2024									
2025									
2026									

TRANSMISSION REVENUE REQUIREMENT ANALYSIS
NET IMPACT [DATA HAS BEEN REDACTED]
(\$1,000)

Year	ENO			EGS-LA			EGS-TX		
	Increase In Fixed Costs	Change In Fuel & Purch Pw. Costs	Net Change In Costs	Increase In Fixed Costs	Change In Fuel & Purch Pw. Costs	Net Change In Costs	Increase In Fixed Costs	Change In Fuel & Purch Pw. Costs	Net Change In Costs
2003									
2004									
2005									
2006									
2007									
2008									
2009									
2010									
2011									
2012									
2013									
2014									
2015									
2016									
2017									
2018									
2019									
2020									
2021									
2022									
2023									
2024									
2025									
2026									

TRANSMISSION REVENUE REQUIREMENT ANALYSIS
NET IMPACT [DATA HAS BEEN REDACTED]
(\$1,000)

Year	ENTERGY SYSTEM		
	Increase In Fixed Costs	Change In Fuel & Purch Pw. Costs	Net Change In Costs
2003			
2004			
2005			
2006			
2007			
2008			
2009			
2010			
2011			
2012			
2013			
2014			
2015			
2016			
2017			
2018			
2019			
2020			
2021			
2022			
2023			
2024			
2025			
2026			

ELI PROJECTS UNDER 230 KV
TRANSMISSION REVENUE REQUIREMENT ANALYSIS
(\$1,000)

Year	Gross Investment	Average Net Investment	Return At 10.34%	Income Taxes	Depreciation Expense	Operation & Maintenance Expense	Other Taxes	Total Revenue Requirement
2002		-	-	-				
2003	-	-	-	-	-	-	-	-
2004	-	-	-	-	-	-	-	-
2005	3,600	1,766	183	64	47	115	53	460
2006	3,600	3,458	357	124	80	117	53	732
2007	19,105	10,850	1,121	390	421	639	279	2,850
2008	19,105	17,929	1,853	645	426	655	279	3,857
2009	19,105	17,173	1,775	618	426	671	279	3,768
2010	19,105	16,455	1,701	592	426	688	279	3,685
2011	19,105	15,770	1,630	567	426	705	279	3,607
2012	19,105	15,117	1,562	544	426	723	279	3,534
2013	19,105	14,491	1,498	521	426	741	279	3,464
2014	19,105	13,888	1,435	500	426	759	279	3,399
2015	19,105	13,298	1,374	478	426	778	279	3,336
2016	19,105	12,709	1,314	457	426	798	279	3,273
2017	19,105	12,121	1,253	436	426	818	279	3,211
2018	19,105	11,532	1,192	415	426	838	279	3,150
2019	19,105	10,944	1,131	394	426	859	279	3,088
2020	19,105	10,355	1,070	372	426	880	279	3,028
2021	19,105	9,767	1,009	351	426	902	279	2,968
2022	19,105	9,178	949	330	426	925	279	2,909
2023	19,105	8,590	888	309	426	948	279	2,850
2024	19,105	8,001	827	288	426	972	279	2,791
2025	19,105	7,428	768	267	426	996	279	2,736
2026	19,105	6,870	710	247	426	1,021	279	2,683

TOTAL NPV @ 8.5%

\$21,276

**ENO PROJECTS UNDER 230 KV
TRANSMISSION REVENUE REQUIREMENT ANALYSIS
(\$1,000)**

Year	Gross Investment	Average Net Investment	Return At 10.34%	Income Taxes	Depreciation Expense	Operation & Maintenance Expense	Other Taxes	Total Revenue Requirement
2002		-	-	-				
2003	-	-	-	-	-	-	-	-
2004	-	-	-	-	-	-	-	-
2005	-	-	-	-	-	-	-	-
2006	1,012	497	51	18	13	33	15	130
2007	1,012	972	100	35	23	34	15	207
2008	1,012	931	96	34	23	35	15	202
2009	1,012	893	92	32	23	36	15	197
2010	1,012	856	88	31	23	36	15	193
2011	1,012	821	85	30	23	37	15	189
2012	1,012	787	81	28	23	38	15	185
2013	1,012	755	78	27	23	39	15	182
2014	1,012	724	75	26	23	40	15	178
2015	1,012	692	72	25	23	41	15	175
2016	1,012	661	68	24	23	42	15	172
2017	1,012	630	65	23	23	43	15	168
2018	1,012	599	62	22	23	44	15	165
2019	1,012	568	59	20	23	45	15	162
2020	1,012	537	55	19	23	47	15	159
2021	1,012	505	52	18	23	48	15	156
2022	1,012	474	49	17	23	49	15	152
2023	1,012	443	46	16	23	50	15	149
2024	1,012	412	43	15	23	51	15	146
2025	1,012	381	39	14	23	53	15	143
2026	1,012	354	37	13	23	54	15	141

TOTAL NPV @ 8.5%

\$1,200

**PROJECTS OVER 230 KV
TRANSMISSION REVENUE REQUIREMENT ANALYSIS
(\$1,000)**

Year	Gross Investment	Average Net Investment	Return At 10.34%	Income Taxes	Depreciation Expense	Operation & Maintenance Expense	Other Taxes	Total Revenue Requirement
2002								
2003								
2004	3,800	1,864	193	67	49	118	55	482
2005	28,857	15,018	1,552	540	387	918	421	3,819
2006	30,374	25,651	2,651	923	606	991	443	5,614
2007	67,497	41,418	4,281	1,490	1,393	2,256	985	10,405
2008	67,497	56,513	5,841	2,033	1,389	2,313	985	12,560
2009	67,497	53,916	5,572	1,939	1,389	2,370	985	12,256
2010	67,497	51,435	5,316	1,850	1,389	2,430	985	11,969
2011	67,497	49,061	5,071	1,765	1,389	2,491	985	11,699
2012	67,497	46,784	4,835	1,683	1,389	2,553	985	11,444
2013	67,497	44,581	4,607	1,604	1,389	2,617	985	11,201
2014	67,497	42,431	4,385	1,526	1,389	2,682	985	10,967
2015	67,497	40,311	4,166	1,450	1,389	2,749	985	10,739
2016	67,497	38,194	3,947	1,374	1,389	2,818	985	10,513
2017	67,497	36,077	3,729	1,298	1,389	2,888	985	10,288
2018	67,497	33,961	3,510	1,222	1,389	2,960	985	10,066
2019	67,497	31,844	3,291	1,145	1,389	3,034	985	9,845
2020	67,497	29,727	3,072	1,069	1,389	3,110	985	9,626
2021	67,497	27,611	2,854	993	1,389	3,188	985	9,409
2022	67,497	25,494	2,635	917	1,389	3,268	985	9,193
2023	67,497	23,377	2,416	841	1,389	3,349	985	8,980
2024	67,497	21,277	2,199	765	1,389	3,433	985	8,771
2025	67,497	19,292	1,994	694	1,389	3,519	985	8,580
2026	67,497	17,506	1,809	630	1,389	3,607	985	8,420
TOTAL NPV @ 8.5%								\$80,386

ENTERGY SYSTEM

TRANSMISSION PROJECTS COST/BENEFIT ANALYSIS COMPARISON OF WITH DSG CASE WITH STUDY BASE CASE : Upper Bound

TABLE OF CONTENTS

	<u>PAGE NO.</u>
SUMMARY OF NET IMPACTS	1
PROJECT REVENUE REQUIREMENT	2-16
CHANGE IN FUEL AND PURCHASED POWER COSTS	17-19
NET IMPACT 2005-2026	20-22
REVENUE REQUIREMENT - ELI UNDER 230kV	23
REVENUE REQUIREMENT - ENO UNDER 230kV	24
REVENUE REQUIREMENT - OVER 230kV	25

**ENTERGY SYSTEM
TRANSMISSION REVENUE REQUIREMENT ANALYSIS
SUMMARY OF RESULTS
NET PRESENT VALUE-2004 THROUGH 2026
(\$1,000)**

<u>Item</u>	<u>EAI</u>	<u>ELI</u>	<u>EMI</u>	<u>ENO</u>	<u>EGS-LA</u>	<u>EGS-TX</u>	<u>Entergy</u>
Increase in Fixed Costs	\$18,966	\$47,722	\$12,726	\$6,200	\$15,629	\$14,211	\$115,453
Change in Fuel and Purchased Power Costs	\$9,582	(\$233,640)	(\$54,362)	(\$88,709)	(\$33,320)	\$19,388	(\$381,062)
Net Impact	\$28,548	(\$185,918)	(\$41,636)	(\$82,510)	(\$17,692)	\$33,599	(\$265,608)

EXHIBIT B

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

Entergy Services, Inc.

)
) Docket No. EL03-132-000
)
)

**MOTION FOR LEAVE TO INTERVENE AND COMMENT
OF THE ELECTRIC POWER SUPPLY ASSOCIATION**

Pursuant to Sections 212 and 214 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission (FERC or Commission), 18 C.F.R. §§ 385.212 and 214, the Electric Power Supply Association (EPSA) respectfully files this motion for leave to intervene and comment in the above-captioned proceeding. On June 10, 2003, Entergy Services, Inc., (Entergy) filed to propose a Weekly Procurement Process to facilitate the integration of merchant generation and other wholesale power suppliers into the Entergy short-term procurement process for serving native load (June 10 Filing). The Weekly Procurement Process also establishes a mechanism for granting short-term firm transmission service. Entergy has asked the Commission to issue a Declaratory Order before September, 2003. After receiving guidance from the Commission on the fundamental elements of the proposal, Entergy will develop and make a formal Federal Power Act Section 205 filing to implement the proposal.

I. MOTION TO INTERVENE

EPSA is the national trade association representing competitive power suppliers, including independent power producers, merchant generators and power

marketers. These suppliers, who account for more than a third of the nation's installed generating capacity, provide reliable and competitively priced electricity from environmentally responsible facilities serving global power markets. EPSA seeks to bring the benefits of competition to all power customers.¹

Many of EPSA's members are authorized to sell energy and ancillary services at market-based rates. Certain EPSA members presently own, or are currently developing, generation projects in the Entergy control area or in adjacent regions that are deliverable to the Entergy control area, and EPSA has participated in many of the Commission's ongoing proceedings on Entergy issues, including the Schedule MSS-4 system agreement amendment and numerous recent filings concerning Entergy's Purchase Power Agreements (PPAs) with its affiliates. Accordingly, EPSA has a direct and substantial interest in the outcome of this proceeding that cannot be adequately represented by any other party.

All pleadings, correspondence and other communications concerning this proceeding should be directed to:

Julie Simon, Vice President of Policy
Nancy Bagot, Senior Manager of Policy
Electric Power Supply Association
1401 New York Avenue, N.W., 11th Floor
Washington, D.C. 20005
(202) 628-8200

II. BACKGROUND

In the June 10 Filing, Entergy explains that it is proposing a new open,

¹ The comments contained in this filing represent the position of EPSA as an organization, but not necessarily the view of any particular member with respect to any specific issue.

independently-monitored bid-based process, under which participating suppliers can compete at the wholesale level to make sales to the Entergy Operating Companies on a week-ahead basis. Entergy's Weekly Procurement Process proposal addresses short-term procurement of merchant generation in the Entergy control area. According to the June 10 Filing, Entergy's current Weekly Procurement Process has resulted in only minimal participation by non-utility suppliers. For this reason, Entergy is suggesting three changes to that process:

(i) moving the weekly procurement decisions from Entergy's regulated wholesale merchant function to the transmission function..., (ii) establishing independent oversight of the process, and (iii) further defining the products that will be bid in the process. Once approved, these changes will facilitate the coordination of the weekly process with transmission decisions, and may enhance market confidence and participation in that process.²

This process will be "overseen by an independent third party ("Independent Procurement Monitor" or "IPM")."³ Further on in the filing, Entergy also mentions that it is evaluating "the possibility of establishing participant funding on an interim basis, i.e., prior to full implementation of the SeTrans Regional Transmission Organization," also to be evaluated by an "independent entity," possibly by the Independent Procurement Monitor as well, thus extending the Independent Procurement Monitor's scope to encompass transmission planning and system expansion.⁴

III. COMMENTS

EPSA has long advocated the concept of including non-utility generation in a security-constrained economic dispatch utilized by load-serving entities (LSEs) in order to optimize generation resources. Hence, EPSA applauds Entergy's proposal as an

² Entergy filing, page 2.

³ Entergy filing, page 4.

⁴ Entergy filing, page 4 – 5.

interim step towards meaningful economic dispatch to prioritize all available generation resources to minimize the hourly cost of electric energy used to serve consumers and achieve the efficiency and environmental benefits of new resources. With this in mind, there are aspects of Entergy's proposal that should be carefully reviewed in order to develop a process that can achieve the shared goals of all participants – maintaining the reliability of the Entergy control area while assuring customers access to the lowest cost generation through a competitive marketplace.

Entergy sees its proposals as a first step toward day-ahead and real-time markets in the Entergy area, pending the development in the future of the SeTrans RTO markets.⁵ The lack of real progress by the SeTrans RTO has been of concern to Southeastern market participants, and will be a concern even if the Entergy proposal is approved. Entergy's proposals cannot simply function as "RTO lite," nor can the Weekly Procurement Process or an Entergy-only participant funding program be allowed to morph into a one-utility RTO. Therefore, while the Weekly Procurement Process can bring benefits to customers, it cannot be used to delay or impede formation of the SeTrans RTO or other appropriate regional organization.

Further, the Commission should not allow the instant proposal to act as a distraction from its focus on mitigation of Entergy market power. While EPSA applauds the objectives of this proposal, we continue to be concerned that the improvements proposed here may not resolve fundamental problems in the Entergy service area which are the primary reason competitive merchant providers have had little success in wholesale markets there.

⁵ Energy filing, page 6.

Within these parameters, EPSA supports the development of a Weekly Procurement Process by Entergy with the following modifications:

- The Weekly Procurement Process must be administered by a truly independent entity;
- An interim, Entergy-only participant funding program should not be a part of this proposal;
- Entergy should look at other aspects of short- and long-term economic dispatch in order to achieve transparency and competition in its markets.

A. The Procurement Process Must Be Conducted by an Independent Administrator

While Entergy proposes that the Weekly Procurement Process be overseen by an independent monitor, the process would be administered by Entergy's own transmission function. In order to achieve the laudable goals set out in the June 10 Filing, the Weekly Procurement Process itself must be administered by an independent entity outside of the Entergy family. Entergy's Transmission Function, until and unless it is spun off from Entergy's system, is not satisfactorily independent to administer such a program, especially in the absence of an independent market monitor in the region. Responsibility for short-term commitment decisions should not simply be shifted to another Entergy affiliate. Rather, an agent with full contractual independence is absolutely essential for transparency and confidence in the marketplace. For instance, EPSA continues to be concerned that the auction process described in the instant filing may provide a price discovery mechanism for Entergy, enabling it to make other purchased power decisions outside of this process or more formal RFP processes, based on and justified by price data gleaned via this procurement program. Limiting access of the competitive bids to an Independent Procurement *Administrator* would help to build confidence – and likely participation – within the merchant power sector. This

limited access to bid information may also assuage the need for Entergy to disclose its own generation costs and price benchmarks to all potential bidders in the procurement process, a concern of some market participants.

Entergy has specified certain independence requirements for the Independent Procurement Monitor and a related monitoring plan in its filing. These are necessary and well-stated requirements, and should extend to an independent *administrator* for the Weekly Procurement Process. As Entergy's filing properly details, the independence criteria and attendant documents must be subject to public comment and Commission approval as part of the Section 205 filing of the Weekly Procurement Process proposal. EPSA also supports Entergy's proposal that regular periodic reports evaluating the performance of the Weekly Procurement Process and its applicable rules be submitted directly to the Commission for review.

B. Participant Funding Cannot Be Adopted Until Entergy's System is Administered by an Independent Operator

In its proposal for a Weekly Procurement Process, Entergy has also explored the idea of implementing an Entergy-only participant funding procedure in advance of adopting such a mechanism as part of the SeTrans RTO. This is clearly out of place in this short-term supply procurement proposal, as participant funding is a tool for long-term planning and system expansion. Further, it is inappropriate for the Weekly Procurement Process Independent Procurement Monitor to play a role in any participant funding program or system planning function. Participant-funded expansion must be administered by an independent transmission operating entity that determines the cost of and responsibility for network upgrades. Moreover, this independent entity must

function within a Locational Marginal Pricing (LMP) market design that can provide appropriate price signals for generator site selection. Generators must have the ability to be assessed as a network resource and secure network access service. Issues associated with the transition from credits to congestion revenue rights (CRRs) must be fully addressed to ensure that companies that fund network upgrades receive the benefits of their investment. In short, key safeguards as contemplated in fully realized, regional RTO proposals must be in place prior to the Commission approving any specific form of participant funding.

C. The Weekly Procurement Process Is One Step Towards Full Economic Dispatch

As Entergy points out, the proposals in its petition are not intended as a substitute for an RTO, though they do represent progress towards competitive markets in Entergy's control area. As such, EPSA hopes that this short-term procurement mechanism is just one aspect of Entergy's move toward open, transparent, competitive markets. Other mechanisms should include a transparent long-term capacity reservation mechanism that evaluates all supply resources equally – Entergy-regulated utility assets, assets owned by Entergy affiliates and independent suppliers. This goal would be buttressed by an open, independently administered RFP process for long-term capacity contracting and network resource designation.

Another important step towards transparent price discovery and competitive markets is the implementation of an all-inclusive day-ahead and real-time economic dispatch program. Only through economic dispatch can all available electric generation resources be economically prioritized in order to minimize the hourly cost of electric energy used to serve customers. Economic dispatch also results in price discovery,

efficiency gains and the realization of environmental benefits of new generation. In tandem with a long-term competitive capacity reservation mechanism and the Weekly Procurement Process administered by an independent operator, an economic dispatch program on a day-ahead and real-time basis will level the playing field for supply resources in the Entergy control area and bring transparency to the markets.

As it considers true economic dispatch, it will be useful for Entergy to propose and develop an approach to defining the true and verifiable cost of its own utility rate-based generation. Certainly its nuclear and hydro units could be considered to be baseload units, and it may be necessary, given current transmission constraints, to identify other utility assets as prioritized reliability units. It is important for the Commission to understand that as long as Entergy's rate-based units are represented in any economic dispatch or competitive bid processes on a variable cost-only basis, competition will not thrive in this market area. Clearly the range of solutions to accommodate the assignment of full cost to utility assets will involve retail rate design decisions under the jurisdiction of the states, but in order to recognize the true economic, environmental and efficiency benefits of newer merchant power sources, this issue must be addressed.


The goals achieved by the Weekly Procurement Process and those described above are shared by all market participant and are both laudable and necessary for the Entergy service area. As such, this proposal should be considered by the Commission on an expedited basis in order to begin to resolve current competitive problems in that market area.

IV. CONCLUSION

WHEREFORE, EPSA respectfully requests that the Commission grant its timely motion for leave to intervene, as set forth above. EPSA applauds the objectives of this plan by Entergy and is particularly appreciative of the notion that Entergy would preclude its marketing affiliates from this process. While careful procedures to provide total protection against insider dealing might be optimal, in the true spirit of competition, this approach is helpful at this time. EPSA supports Entergy's Weekly Procurement Process with certain modifications. Implementation of a properly structured process, which has been fully considered by the Commission, should be expedited as an interim step towards a regional RTO structure.

July 10, 2003

Respectfully submitted,

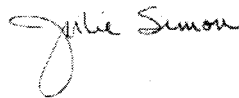


Julie Simon, Vice President of Policy
Nancy Bagot, Senior Manager of Policy
Electric Power Supply Association
1401 New York Ave, NW
11th Floor
Washington, D.C. 20005

CERTIFICATE OF SERVICE

I hereby certify that I have served a copy of the comments by first class mail, postage prepaid, upon each person designated on the official service list compiled by the Secretary in this proceeding.

Dated at Washington, D.C., July 10, 2003.

A handwritten signature in cursive script that reads "Julie Simon".

Julie Simon